STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

&

STATE OF MAINE

PUBLIC UTILITIES COMMISSION

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Unitil Corporate Headquarters
6 Liberty Lane West
Hampton, New Hampshire

MORNING SESSION ONLY

RE: **NEW HAMPSHIRE PUC DOCKET NO. DG 11-290**
NORTHERN UTILITIES, INC. - N.H. DIVISION:
MAINE PUC DOCKET NO. 2011-526
NORTHERN UTILITIES, INC. - MAINE DIVISION:
Integrated Resource Plan.
(Joint Technical Session)

Court Reporter: Steven E. Patnaude, LCR No. 52

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P R O C E E D I N G

MS. MacLENNAN: Good morning. Thank you for helping to arrange this technical conference. This is a joint technical conference between the Maine Commission and the New Hampshire Commission. The Maine docket is 2011-526. And, I'll let the New Hampshire folks provide the number for the New Hampshire docket in a moment.

We may have actually accomplished introductions informally. But, for the record, it probably makes sense to go around the table. I'm Carol MacLennan, the Presiding Officer for the Maine proceeding. And, with me is Michael Simmons, a Utility Analyst, and also Lucretia Smith, a Utility Analyst. And, then, I'll --

MR. JORTNER: I'm Wayne Jortner, with the Maine Office of Public Advocate. And, my colleague, William Black, will be here any moment.

MR. ROSENKRANZ: John Rosenkranz, consultant for the Maine Public Advocate's Office.

MR. EPLER: Gary Epler, Unitil.

MS. HARTIGAN: Ann Hartigan, Unitil.

MR. WELLS: Fran Wells, Unitil.

MR. FURINO: Rob Furino, Director of Energy Contract for Unitil.

MR. GULLIVER: Good morning. John Gulliver, of Pierce Atwood, representing Unitil.

MS. BARTOS: Melissa Bartos, with Concentric Energy Advisors, working with Unitil.

MR. SIMPSON: Jim Simpson, with Concentric Energy Advisors, assisting Unitil.

MR. GOODWIN: I'm Dan Goodwin, from Unitil.

MR. G. SIMMONS: George Simmons, Regulatory Services, Unitil.

MS. THUNBERG: Marcia Thunberg, New Hampshire Public Utilities Commission.

MR. FRINK: Stephen Frink, New Hampshire Public Utilities Commission.

MR. WYATT: Bob Wyatt, New Hampshire PUC.

MR. McCLUSKEY: I'm George McCluskey, New Hampshire PUC.

MS. MacLENNAN: Great. I believe we sent through e-mail a couple of days ago an agenda, sort of a general, topical agenda. And, the format we'd like to proceed in is New Hampshire Staff to begin the questioning, with Maine Staff and Public Advocate interjecting, I guess, questions, as they fit in, or the

OPA, if you like, can go at the end, whichever your preference is.

MR. McCLUSKEY: Okay.

MS. MacLENNAN: It's my hope, I guess I'll just say this, that my expectation that we may be able to end by 3:00 today. But we'll see how the questioning goes.

MR. McCLUSKEY: Okay.

MR. GULLIVER: We may have a preliminary --

MR. FURINO: Yes. If I could, just briefly. I think the majority of you are familiar with most of our staff. But, since we have some new people here today, I just wanted to make sure --

MR. McCLUSKEY: Okay.

MR. FURINO: -- that people were familiar with which portions of the Resource Plan that individuals on our team have contributed to. And, I thought also, you know, we've had a recent exchange with regard to updating and questions about a given data request. So, we have some follow-up handouts to provide, you know, in that regard.

If I look at the "Table of Contents" in the IRP, and go to the first major sections. We have two sections, the "Demand Forecast" and the "Planning Standards". Those were prepared primarily by Concentric Energy Advisors. So, again, Jim Simpson and Melissa Bartos are here to speak on that.

The "Resource Portfolio Assessment" was largely based on the work of Fran Wells, in terms of the SENDOUT modeling, and with assistance from Ann Hartigan, in terms of the portfolio and market conditions.

We have a "Demand-Side Management" section, but we do not have anyone here today to speak directly to demand-side management, given the agenda that was provided for today.

And, then, just briefly, I wanted to -- I think you all know Fran Wells. He's been representing Northern at all of our cost of gas filings. Ann Hartigan is our Trader for Northern Utilities. Ann has extensive history in natural gas trading, and she's our expert in natural gas markets, with, and she can help me, if need be, but with Adams Resources, Select Energy, --

MS. HARTIGAN: Uh-huh.

MR. FURINO: -- five years with Sprague Energy?

MS. HARTIGAN: Yes.

MR. FURINO: And, she's been with

Northern for two years now. Dan Goodwin is our Energy Analyst. All the data analysis, things like collecting data, customer data, operational forecasts that the Company prepares, Dan is responsible for overseeing our parameters that feed our daily operational forecasts for Northern. And, he worked closely with Jim and Melissa in developing the demand forecast itself. So, he's very familiar with that, and he's one of our go-to data guys. So, just wanted to round out, sort of give a little introduction for our team here.

Yesterday, there were questions raised about our Attachment Staff 1-37. And, we provided that initially as a PDF file. The Maine Commission Staff had asked for the Excel file for that. And, after receiving that, raised the question of "well, why is there very low", I guess, "growth for the" -- I guess it was the "G40 sales customers?"

MR. GULLIVER: Yes.

MR. FURINO: And, we found a modeling error. So, I corrected that last night, and sent around a new revised version of that. I have a printout of that here today, just so that you'll have it. I'll send what I believe to be half of these each way around the table. The error itself --

MS. THUNBERG: I'm sorry, Rob. Can I just interrupt?

MR. FURINO: Yup.

MS. THUNBERG: The document you're passing around, is that the one you sent around in this morning's e-mail?

MR. FURINO: Yes. I think I sent two separate documents. Actually, this morning -- it's not the one I sent this morning.

MS. THUNBERG: Okay. All right.

MR. FURINO: It's the one that I sent last night.

MS. THUNBERG: Thank you.

MR. FURINO: So, it's a printout of the Excel file I sent last night.

MS. THUNBERG: Thank you.

MR. FURINO: And, you know, we will refile this with New Hampshire, when we submit the Set 3 responses. And, this will be "Revised Attachment Staff 1-37".

MS. THUNBERG: Perfect. That way our discovery person in our Docket Room will get it electronically and put it in the appropriate electronic file. Thank you, Rob.

MR. FURINO: Right. And, you know, the error that we had was that, if you go to, say, the second page, and it was all in the "Summary" information. Thank you, George. Where we have gas years 2005-06 through 2010-11, off to the side we were summarizing by years 1 through 6, and the values 1 through 6. Because, if you look at some of the data in the columns, if you look at the far right, you see the "Sales" column that says "G52", you'll see a lot of fives, and a few sixes in there. Well, what happened was, our formula was referencing not just the year number that we assigned, year 1 through 6, it was also picking up data from within the dataset that we were summarizing. So, it didn't correctly state that.

So, the revision we sent around last night corrects for that. And, as you can see, there has been no loss in the sales customers there.

Also, I provided this today, because Maine had asked for data on customer migration for the two divisions. So, this attachment provides that. And, so, as you can see, if you're looking at Page 2, you can see the split for our G and T40 customers. Where now you see, as of 2010-2011, 94 percent of those customers are on sales service, 6 percent are on transportation service. And, this is in terms of sales, and not customer counts.

And, as you go to larger class groups, you can see -- well, you see similar numbers for the 50 group, which are also small customers. The 41/51s are in the 67, 67 -- 66 percent range for sales, and 33, 34 percent range for transportation. And, the larger group of customers, the 42s and 52s, you see sales at 43 percent, transportation at 57 percent, for the 42s. For the 43s, only 18 percent is sales customers, and 82 percent are transportation.

Those are the New Hampshire numbers. The comparable numbers for Maine are listed on the last sheet here.

So, I just wanted to present that to you today, draw your attention to it. The e-mail that I did send around this morning, with the call-in instructions that we turned out not to need, so it's good to see John in person today, present the capacity exempt customer accounts that we were able to obtain for the period of December 2008 forward. And, so, there is a sheet for Maine and a sheet for New Hampshire on that, and we'll hand that around.

So, those are the handouts that I have. In addition, there were some questions about, we saw anyway, in New Hampshire Staff Set 3, discovery about EDD data and what the Company receives from Telvent, its weather service provider.

MR. WYATT: Uh-huh.

MR. FURINO: And, we do have a copy of a periodic forecast e-mail that we receive. And, I believe we receive this four times a day. We can update that through our agreement with Telvent, receive it as frequently as we require.

So, I'll hand that around, just so that people have it for reference. And, when the time comes to talk about EDDs and weather data and what your questions are, we can refer to that at that time.

MR. WYATT: Okay.

MR. FURINO: So, that's it that we had. So, New Hampshire Staff is going to --

MS. MacLENNAN: Well, could I jump in with one more preliminary? And, that is just to let you know that we do have some questions regarding efficiency or DSM for the Company today. I didn't -- we didn't identify that specifically, we were thinking of it as within the load forecast area.

MR. FURINO: Okay. And, we will respond as well as we can, and certainly take back anything that we don't feel comfortable responding to directly.

MS. MacLENNAN: Okay. All right. Thank

you.

MR. McCLUSKEY: Okay. I guess New Hampshire is starting. We're going to kick off with the -- first of all, I'd like to apologize, I don't feel quite as organized as what I would normally do, given that I had two sets of discovery to issue yesterday in two separate proceedings, and that was quite stressful. So, I may be bumbling along today, but I guess we'll get there.

I'm going to kick off with the planning, a couple of planning load questions. But I want to -- you described, Rob, the content of the IRP. Based on the review to date, I think certain New Hampshire Staff testimony is probably going to focus on DSM assessment, which I discussed at the first tech session. And, we're not going to address that today. We know what we're going to say on that issue.

The other area of concern is supply modeling. The more we review and look into the filing, the greater our concerns are. My initial reaction to the filing was "Hmm, this is pretty good." The more we look into it, the more concerns that we have.

On the demand forecast/planning load, we've got a couple of questions today, but I wouldn't say that major concerns have jumped out of the IRP in that particular area. So, Jim and I are not going to be butting heads, which is very unusual, I have to say. And, so, --

MR. GULLIVER: We were selling tickets on that premise, you know.

MR. McCLUSKEY: So, we --

MR. G. SIMMONS: So, we can dismiss him now?

MR. McCLUSKEY: I'll ask him a few questions, then he can go, if he wants.

Okay. So, on the -- what I call the "planning load", Set 2-2, we asked I think it was a multipart question. And, that question, by the way, was referencing Staff 1-1. And, in particular, the attachment that was provided to that response. And, do you have that?

MR. SIMPSON: Yes. I don't want to interrupt you. I'll just say that, sorry, we missed the import of the question. And, you know, the follow-up 3 was sort of the dope slap we needed. And, by "we", of course, I mean "me". So, what I'm going to pass out is what we would have, should have provided in response to 2-2.

MR. McCLUSKEY: Okay. Well, --

MR. SIMPSON: And, I can walk through the --

MR. McCLUSKEY: Well, for the benefit of the -- why don't you let me kind of set it up first.

MR. SIMPSON: That's fine.

MR. McCLUSKEY: Then, you can explain --

MR. SIMPSON: Yes.

MR. McCLUSKEY: -- how you would have in discovery.

MR. SIMPSON: Yes.

MR. McCLUSKEY: And, then, the Maine people get the benefit of that response. So, as I was saying, the 1-1 was effectively focusing on the marketing adjustment component of the planning load. And, I think we asked "provide the support for your planning load numbers over the five year period." And, so, you provided Attachment 1, and we compared the quantities for New Hampshire, the demand quantities in Attachment 1 to quantities that were in Table III-3.

And, so, in Question 2-2, we said "okay, tell us how the numbers in Attachment 1 support the numbers in Table III-3." And, I suspected you had misread the question, though, maybe I could have been a little bit more refined in how I asked Part (a), and more direct, which I normally am. But let's try -- I admit that and recognize that. So, anyway, you missed the point.

MR. SIMPSON: Yes.

MR. McCLUSKEY: And, so, I'm looking at the numbers in Attachment 1-1 to New Hampshire and saying "you don't support the numbers in Table III-3." So, can you resolve that riddle?

MR. SIMPSON: Absolutely, we can. So, if people will refer to the page that was just passed out. The first four -- so, this is for the forecast period, 2011-12 through 2015-16. The first four columns are direct copies from Attachment Staff 1-1. And, then, we added the "total" column to add up the four prior columns. And, so, those totals are the same as one of the columns in Page Appendix III-84.

MR. McCLUSKEY: One moment again, Jim. So, the first four columns of this sheet --

MR. SIMPSON: First four columns are copies from Attachment Staff 1-1.

MR. McCLUSKEY: For New Hampshire or for Maine?

MR. SIMPSON: Oh. They are for New Hampshire. There was a response somewhere along the line, which identified that the Staff 1-1 headings are reversed.

And, what is shown as "Maine Division" is actually "New Hampshire", and what is "New Hampshire Division" is actually "Maine". That's on Attachment Staff 1-1.

MR. McCLUSKEY: I wasn't aware of that. So, what's the -- when did you send that out?

MR. SIMPSON: That came from the Company at some point, I think, right?

MR. FURINO: I'm really not sure about that, Jim.

MR. SIMPSON: Okay.

MR. FURINO: I'm sure it has. Just trying to catch up.

MR. McCLUSKEY: Okay. So, with that correction then, the first four columns that you're showing on this new sheet are New Hampshire numbers?

MR. SIMPSON: They are.

MR. McCLUSKEY: Okay.

MR. SIMPSON: Yes.

MR. McCLUSKEY: So, this adds up to "461,333". And, go from there.

MR. SIMPSON: Yes. So, you highlighted the "461,333" for the year 2015/2016.

MR. McCLUSKEY: Yes.

MR. SIMPSON: And, if we go to Page

Appendix III-84. And, the Page Appendix III-84 is "Table NH-MP-1 Marketing Program". And, the first three columns of numbers are for the normal, under normal weather conditions, and then the last three columns are for design conditions. So, if you compare the "Total Split Year" column numbers to the numbers in the sheet that I just handed out for -- in the "total" column, that's the total of the numbers in Attachment Staff 1-1, those numbers match. Okay? So, that's the correspondence between Staff 1-1 and Table NH-MP-1.

And, as the heading in the page that I just passed out states, all those numbers are for the total marketing adjustment. That is, the total planning load, as well as the capacity exempt piece of the marketing adjustments. The assumption being that some of the added load will opt to be capacity exempt.

MR. McCLUSKEY: I'm not getting this.

MR. SIMPSON: Okay.

MR. McCLUSKEY: Let me kind of direct you through it.

MR. SIMPSON: Yes.

MR. McCLUSKEY: So, Table -- this is on Page III-12 of the IRP. Okay?

MR. SIMPSON: Yes.

MR. McCLUSKEY: And, Table III-3 is for the New Hampshire Division, correct?

MR. SIMPSON: Yes.

MR. McCLUSKEY: And, it's referred to as the "Base Case Normal Year Planning Load".

MR. SIMPSON: Yes.

MR. McCLUSKEY: And, the 2015/16 figure of "339,086" --

MR. SIMPSON: Yes.

MR. McCLUSKEY: -- is shown on the sheet that you just handed out for that year. Okay?

MR. SIMPSON: Yes.

MR. McCLUSKEY: Now, the figure of "461,333", which is shown on that sheet, is that a base case or --

MR. SIMPSON: It's a base case total load. The "461,333" is planning plus capacity exempt. The numbers that you're seeing on Table -- on Page III-12, in Table III-3, is planning load only. So, George, --

MR. McCLUSKEY: Oh, I see.

MR. SIMPSON: -- on the sheet that I passed out, okay, what I did, the math that I did was to start with the total that we developed from Attachment Staff 1-1.

MR. McCLUSKEY: Okay.

MR. SIMPSON: And, then, I -- next to it I put the planning load that we had provided in Table III-3. And, then, I did the subtraction of -- I subtracted the planning load from the total load, and those numbers then match up. It's -- first of all, it's the difference between the two sets of numbers, and it's also equal to the "capacity exempt" portion of the Marketing Program. And, those numbers are shown on Page Appendix III-86. There's a rounding error for the last year, but otherwise they match up.

MR. McCLUSKEY: Okay. I get it now. So, --

MR. SIMPSON: Yes.

MR. McCLUSKEY: Okay. So, you can see the workpaper that you provided in response to the question does not support the numbers on Table III-3, because we were not aware that one was referring to total planning load, with capacity exempt, and the other one was referring to planning load with capacity exempt marketing adjustment excluded.

MR. SIMPSON: Right. I guess -- I guess what could have been made clearer was that Staff -- Attachment Staff 1-1 was the total marketing load.

MR. McCLUSKEY: That's correct.

MR. SIMPSON: Yes.

MR. McCLUSKEY: Okay. I understand the difference now. Okay. Now, this switch from switching the labels "New Hampshire Division" and "Maine Division", is this the -- oh, this was an attachment. This was not in the IRP.

MR. SIMPSON: That's correct.

MR. McCLUSKEY: So, presumably, you've got the labels correct in the IRPs, is that right?

MR. SIMPSON: We did. We did.

MR. McCLUSKEY: Okay. That's good. Okay. So, that answers that question.

Now, several questions had asked for information on planning load, historical planning load, going back to 2005/06, I think was the first year. And, the Company was not able to provide that, because of the alleged inability to access capacity exempt load data?

MR. SIMPSON: That's correct.

MR. McCLUSKEY: For the years prior to 2010/11 or was it 2009/10?

MR. SIMPSON: There was data that was provided to the Company starting in July 2008. So, that was just right before --

MR. McCLUSKEY: Okay.

MR. SIMPSON: -- the acquisition.

MR. McCLUSKEY: Okay.

MR. SIMPSON: And, we tried to use that data in our modeling efforts. That is, this is the "capacity exempt" piece.

MR. McCLUSKEY: Okay.

MR. SIMPSON: And, it just was not possible. There was -- there were disconnects between the billing data that Unitil had been provided and actual numbers, you know, what actually happened. So that implausible -- the capacity exempt numbers produced implausible results, like the capacity exempt totals for some months were greater than total transportation.

MR. McCLUSKEY: Okay.

MR. SIMPSON: And, there was no way to go back -- no way that the Company could find to go back and clean up that data. So, that data was not usable. The first usable data was the data that the Company started acquiring and developing themselves, once they took over the company, took over Northern.

MR. McCLUSKEY: Yes.

MR. SIMPSON: So, that is December 2008 and on. So, for modeling purposes, December 2008 didn't do us any good, because we had to use quarterly data, and we didn't have the first two months of that quarter. So, for modeling purposes, the first data that we could use from the capacity exempt data that the Company could provide us was the data starting with January of 2009. So, that's the same as Quarter 1 2009. And, for purposes of reporting in the tables that were dealing with a gas year and with a peak -- a gas peak period, because we didn't have the capacity exempt data starting in November of 2008, we couldn't report the full 2008/2009 peak period, which would run from November 2008 through March 2009. So, in the tables, the first period that we could start reporting was the off peak period of 2009. For our modeling purposes, the first data that we could use was Quarter 1 of 2009.

MR. McCLUSKEY: I see.

MR. SIMPSON: And, that's a much more lucid description than I provided in the responses, for which I apologize.

MR. McCLUSKEY: No. That's fine. I think we got the gist of the responses. We don't have the data for the period in order to respond to some of our questions on the historic period.

MR. SIMPSON: Right.

MR. McCLUSKEY: Now, I think you indicated that you had some data but for the historic period, but it wasn't something of the quality that you required for the work that you were doing?

MR. SIMPSON: We knew it was unreliable, yes.

MR. McCLUSKEY: Okay. Now, the Staff has data on sales and customer numbers for both grandfathered and non-grandfathered transportation customers for the Northern Utilities' New Hampshire Division back to 2004. And, so, we're wondering why the Company doesn't have this information? And, I think the best -- so, kind of raises a couple questions. We said it's for the New Hampshire Division, that's why we have it. One would expect that a similar table would have been put together for the Maine Division. So, when we hand this out, if the Maine Staff could inquire, when it gets back to the office, as to whether they have similar data for this period, then, if it's determined to be useful, quality data, then we'd like to have the Company fill in some of the holes for the historic period that appear in the IRP. So, I've just got one copy at the moment. And, Gary, do you want to have somebody --

MR. G. SIMMONS: I'm the lackey.

MR. McCLUSKEY: Yes.

MR. G. SIMMONS: Just all these pages?

MR. McCLUSKEY: Yes. You probably want to make several copies of it.

MR. G. SIMMONS: Oh. Oh, sure.

MR. McCLUSKEY: So, why the Company doesn't have this? I don't know what the answer to that is. But we certainly received it on a regular basis from the prior owners of Northern Utilities. And, --

MR. WYATT: And, also from the Unitil folks. In the monthly -- for a while they were provided in the monthly over/under cost of gas reporting. It was a supplemental schedule of transportation customer counts for grandfathered/non-grandfathered, and the same thing for grandfathered and non-grandfathered FT loads by rate class.

And, I think Northern now provides that under separate cover electronically, electronic filing monthly, that data, in the same template format. That's been used since 2003 or 2004. You'll see, when you get your copy.

MR. McCLUSKEY: Yes. So, if it is the kind of data that you would have wanted, Jim, the only reason for raising it is -- it's not a big deal to us that you don't have it. But, if it is quality data on the New Hampshire side, and Maine has similar data, we would like the Company to go back and fill in those gaps, that that would be helpful, in terms of our review of where the planning load is going forward. That's essentially what we want to do. We want to see how -- what you're planning going forward and how it's been in the past. Having two years is just not sufficient to make that analysis.

MR. SIMPSON: It's not ideal.

MR. McCLUSKEY: It's not ideal.

MR. SIMPSON: We agree.

MR. McCLUSKEY: That's correct. Yes.

MR. WYATT: I think those reports were requested by Staff, by me, back when I first came on board at the Commission, and they were referred to as "Migration Reports", "Transportation Migration Reports".

MR. SIMPSON: Did Joe prepare them? Ron --

MR. WYATT: Ron Gibbons.

(Court reporter interruption.)

MR. SIMPSON: Joe Ferro or Ron Gibbons?

MR. WYATT: Ron Gibbons put the reports together. Joe Ferro was familiar with them, as was Ron Slate. But Ron Gibbons needed to pull the data from the billing system, I believe.

MR. McCLUSKEY: Okay. So, those -- those are my questions on planning load. I don't know if the Maine Staff has anything?

MS. SMITH: Just while they're thinking about it, I know that we don't get or we didn't get similar migration reports in Maine. So, anything we would have had would have come in in a cost of gas filing. And, we didn't get those separate reports that you're referring to. So, --

MR. WYATT: Uh-huh. Okay. Another area where they might have been detailed would have been in the cost of gas reconciliations, perhaps. But, with capacity exempt, I guess it wouldn't be likely that those would have been excluded, because they --

MS. SMITH: And, so, we can look back and see what was in the cost of gas filings. But I know there are no reports separate from the cost of gas filing. And, of course, Maine didn't have grandfathered customers, nor did we start as early. So, there would be not as much data anyway that would be missing, if you will, in that we didn't start with the capacity exempt or capacity assignment until 2006-2007?

MS. MacLENNAN: January 2006.

MS. SMITH: So, --

MR. McCLUSKEY: Jim, it seems to me, just while Lucretia was talking, that even if we don't have corresponding Maine data, I think you could do the historical build-out for New Hampshire at least, based on the data that you've got.

MR. SIMPSON: Right. They are separate issues.

MR. McCLUSKEY: Are separate issues.

MR. SIMPSON: Yes.

MR. McCLUSKEY: Yes. And, since we're interested in the development of the planning load for New Hampshire, that should be sufficient.

MR. FURINO: George, just a quick question?

MR. McCLUSKEY: Yeah.

MR. FURINO: The data that New Hampshire has, and maybe I'll see it when it comes around, is it available by rate class?

MR. WYATT: Yes.

MR. McCLUSKEY: Yes. It is.

MR. FURINO: That's great. We're just peeking at the handout I just made for the capacity exempt loads in Maine. You know, they're saying, you know, it didn't start -- capacity exempt status didn't start until 2006 in Maine. According to the data we have here, October 2008 was the first recorded month. And, you see only a total of eight customers are listed. So, maybe it's a finite -- and there are two classes without any capacity exempt customers as of that point, and then three classes with one customer each, and then one class with five customers. So, it could be somewhat isolated. So, from an analysis standpoint, you might be able to piece together some of the puzzle.

MR. WYATT: Rob and Lucretia, when did Maine first unbundle and allow transportation? What year was that? Was that 2000 --

MS. MacLENNAN: 2006, starting in January.

MR. WYATT: Okay. And, at that point in time -- excuse me. At that point in time, all transportation load in Maine was capacity exempt, I believe, is that correct?

MS. MacLENNAN: Prior -- prior to that date, we had no capacity assignment policy.

MR. WYATT: Right. So, --

MS. MacLENNAN: But there was no grandfathering of that --

MR. WYATT: No, no, no.

MS. MacLENNAN: Yes.

MR. WYATT: You didn't refer to it as "grandfathering". But they were, in essence, capacity exempt. They weren't assigned capacity.

MS. MacLENNAN: Right.

MR. WYATT: But they were billed for the delivery portion of their bill from Northern billing systems. So, the data should be available on, if you have billing records, on the -- all of that load would have been "capacity exempt" at the start, until after the docket where you developed your delivery service terms in the tariff.

MS. MacLENNAN: But is the point of your analysis, though, to know the proportion of customers, transportation customers that fall into the "capacity assigned" versus "non-capacity assigned" or going from the point in time after which Maine had a policy?

MR. WYATT: Well, the Company's filing has different categories. They have "total load", which includes capacity exempt and capacity assigned. And, then, they have "planning load", which excludes capacity exempt.

MS. SMITH: And, for Maine, would

include only 50 percent of the capacity assigned.

MR. SIMPSON: There's really two categories, I think of there being two categories of transportation customers in Maine. One is the customers that were taking transportation service before the resolution of this issue. And, those customers are subject to the 50 Percent Rule. And, then, there's new customers that first received service from Northern after that date, and they could opt out of the capacity assignment. And, so, therefore, those customers, 100 percent of their volumes are capacity exempt. So, when we have to look at Maine, we have to keep -- think of these two categories, when we're developing the forecast of capacity exempt and, by subtraction, the planning load.

MR. WYATT: Uh-huh.

MR. M. SIMMONS: I had a brief question going to the DSM. And, that is, on ADR 1-19, and it's really just more of a process question than a technical question. But, in the response, it indicates that you've asked for information from the Maine Efficiency Trust. And, one, I wanted to find out if you received that yet? And, then, the second part of that is that it states that you haven't participated in the Triennial Plan process. And, this summer, the Trust is starting their second

Triennial Plan. And, I was wondering if Northern had any expectation to be involved in that process?

MR. FURINO: We're going to have to take both of those requests back.

MR. M. SIMMONS: Okay.

MR. FURINO: And, I personally was curious and wanted to know and had not yet found out whether or not we -- Northern had been able to obtain data from Maine Efficiency -- Efficiency Maine. So, that's something we're definitely interested in follow-up on that. And, as far as participating in the Triennial Planning, we'll get back to you on that as well.

MR. M. SIMMONS: Okay. Thank you.

MR. McCLUSKEY: Anything else on demand forecast?

MS. MacLENNAN: Yes. I have a recollection, and I apologize for not having a reference, but it may have been in the cost of gas case or a response in this case. That indicated the growth for Northern Maine Division was well in excess of the 2 percent planning benchmark. And, I wonder if, first of all, you can point us to, if it is a response in this case, if you could point us to it, it might help. But, then, also if you could discuss, and I'm obviously not one of the technical people here, why or what relevance, how you would incorporate that or whether you incorporated that into your thinking about developing the load growth metric? Is my question clear?

MR. SIMPSON: I wouldn't mind a second try.

MS. MacLENNAN: All right. It appears to us, through data that's come in from the Company, that Maine at least has sustained a rate of growth recently that's well in excess of the 2 percent planning assumption that you've used. And, I'd like to know more about whether the Company took into consideration the actual growth, recent growth in the Maine Division, or not, or how it did so?

MR. SIMPSON: Yes. I'll try to be as concrete and specific as I can. But, you know, some of this just deals with the models and how the models work. But, for part of my response, let me say that the models certainly look at and take into account all the historical data that we use. And, so, to the extent that an uptick in growth is reflected in the historical data, then that will get picked up by the model. And, particularly, if there's things going on that seem to indicate that there's some new basis for customer response, that -- and that the statistical relationships that we had developed over a period of time seem to be changing in the recent history, we're very mindful of that. You know, I mean, there's just amazing things going on in the gas industry right now. So, we're specifically looking at the recent history, to make sure that our models fit well with the recent historical data.

But, still, we understand, based on talking with the Company, that -- that what they have been experiencing, in terms of added customers, added load, in recent times is just sort of phenomenal, and is beyond what we have seen in historical data. And, that really is the primary basis for the marketing adjustment.

And, might I add that we do this kind of demand forecasting for other gas utilities, mostly in Massachusetts, and they are seeing the same things. They're seeing that -- that there's been a recent additional burst of added load of new customers that is sort of beyond anything in the historical period. And, that's despite the fact that, in the recent history, that we have seen the same sort of conditions that are favorable to added customers, added gas load. It just seems to be that customer responsiveness to the price differential between gas and oil is picking up. It's as though people are accepting that this gap is here to stay for at least a while. And, oil customers have accepted the fact that they have missed out on the benefits of switching to oil for the past couple of years, even though all the signs pointed to that being an okay decision, and they don't want to perpetuate, you know, their inertia. They're going to switch to natural gas. So, that's the basis for the marketing adjustment.

Did any of that get at what you were focusing on?

MS. MacLENNAN: Well, it did, except I still have a bit of a question about the degree to which that recent information would be reflected in the metric of the model. Is it the case that the Company believes it's -- I think you used the word "phenomenal", I'm wondering if the subtext there is "anomalous", that this is an anomalous situation, and, therefore, it's best to smooth it out and use a historic -- a more historic trend, rather than the more recent data, to project load going forward?

MR. SIMPSON: Okay. I'll try this one. That the model looks at historical data, and tries to make sense of the historical data and the changes in the historical data by adding in factors, like the price of natural gas, adding in factors like the increase in population, in some measure of increase in population, as that would affect customers, the number of customers that Northern has on the system. And, you know, we try different -- different kinds of variables to capture that effect. We try the number of households, we try the number of construction in houses -- house -- new construction households completed. You know, we try a number of different variables, all to see what matches up the best.

And, then, as far as the model goes, you know, it tries to -- we have tried to find the best variables that explain what's going on in the historical period, and then were -- we rely upon the vendor that we have purchased this data from, and the forecast that they make for all of these variables. You know, so, to the extent that the vendor has an optimistic view, generally, of what's going on in the economy in New Hampshire and the economy in Maine, then that's what's reflected for the base -- the base forecast, before adding in the marketing adjustment.

Let me make one other observation. Which is that, when we're talking about and hearing of news reports and just general understanding of load additions that are occurring, because customers are converting from oil to natural gas, keep in mind that the existing customers, the customers before these new customers switch, their consumption behavior isn't static. We seem to capture, in the historic data, reactions to the customers and their customer -- the customer behavior. And, so, as the existing customer base adds to the energy efficiency measures in their house, you know, the demand level of the existing customers, to which, you know, these new customer loads are added on, is -- it's all factored together. So, when we hear that the -- that the customer conversions, people switching from oil, is going to lead to an increase in demand of, you know, so many units, that doesn't -- that doesn't translate into that kind of increase in the total demand, because offsetting that is somewhat energy conservation and other customer reactions.

MS. MacLENNAN: And, then, let me just focus you on the Maine Division, to see what marketing adjustment you may have made for the Cast Iron Program. If you could describe what you considered and what you ended up doing as a result of that, customer additions in that program?

MR. SIMPSON: We think that the detail of the marketing program has been provided in one of the responses. We did not receive that response, because it was -- it was confidential. So, I think you people have that response. And, you know, obviously, at the time that we were developing the forecasts, we were -- we were in that spreadsheet, and we were using it. But, you know, just we -- what you have been provided, we don't have a copy of. And, I think, amongst -- amongst all of us, we could probably walk through the spreadsheet, since it's been a while since we've worked with it, it may be a little clunky for us to do it. Where, you know, it may take us some time to refresh our memory on it on how things work. But I know that, specifically, there was reflected in the marketing program, right? Yes. I mean, we seem to recall that the Cast Iron Replacement Program was specifically reflected, but we just don't have the details.

MS. MacLENNAN: Okay. Well, I think there may be other, maybe the Public Advocate will have questions on this as well?

MR. JORTNER: One question, just to follow up. One of the barriers toward conversion from oil to gas is the cost, that many people can't afford to convert their --

(Court reporter interruption.)

MR. JORTNER: The conversion of oil to gas, by converting heating systems or burners. And, Northern used to be in the business of promoting those things; it's not anymore. But couldn't that have a large effect on the forecast, if there was some low income loan program or some other type of incentive program to encourage those conversions, couldn't that vastly increase the number of conversions and affect the forecast?

MR. FURINO: You know, I think I could maybe just make a few general comments about the marketing adjustment. Wayne, I don't have the specifics on what particular programs the Company might have available. I understand that the Company is interested in trying to maximize customer conversion. So, you know, at a minimum, we're doing what we can. I think the local constraint is the construction that we can accomplish during the construction season.

So, as I understand it, there is a list of customers that are waiting to be signed up. And, it's a question of "how close they are to the main?" "Are they on the main?" "Does it involve a conversion?" We are trying to convert non-heating customers to heat, which requires that kind of investment. And, exactly what type of programs we're offering, I'm not -- I can't speak to it, but we can look back.

More generally, in terms of the marketing adjustment, there are really five types of marketing initiatives that were looked at. One of the pieces was to try to add new on-the-main customers, so, increase saturation. So, the saturation rate I believe in New Hampshire is a little over 50 percent; it's a little under 50 percent in Maine. And, the goal that we have reflected in the marketing adjustment is to increase that percentage by -- or, to gain one percent annually of what's available on the main. So, that's one, is on-the-main saturation.

Another piece is assumptions related to increasing use among low-use customers. So, that's the customers where we're trying to convert non-heat customers to heat. And, if you saw the handout that Jim sent around, you saw that the residential non-heat for the marketing adjustment has negative values, and the residential heat has positive values. So, that reflects that. The target is to try to get 3 percent of those low-use customers to increase their usage. Okay?

The third piece is to try to reactivate inactive accounts. So, we've looked out and defined a set of inactive accounts. And, among those, we're targeting

10 percent, is what's reflected annually. So, whatever that amount is, 10 percent of that is an assumption that's flowing into the marketing adjustment.

Another piece of it, which may not seem as overt, but is to retain -- improve the retention of existing customers. So, we look at our annual "customer loss rate", "defection rate", whatever you want to call it, and, you know, trying to reduce that rate, cut that rate in half was the goal. So, in that case, you don't really see customers being added, but you're not seeing customers leave the system. So, that's another aspect.

MS. MacLENNAN: Rob?

MR. FURINO: And, I think, historically, I think the Company has made investment to attract new customers. And, so, it's longer term, sort of before the witnessed boom cycle, you know, we have a marketing group that will go out and say "Hey, we've documented that we've installed, you know, X number of customers that have expected, you know, Y annual loads." And, then, we compare it to the facts and say "well, you know, you didn't really see that." Well, one of the reasons is because we've also lost a couple big accounts. We've lost a couple other accounts. So, it's to try to cut down on that shrinkage.

I'm sorry. Carol, you had a question?

MS. MacLENNAN: I'm sorry. I just wanted to clarify that the marketing plan that you're referring to, is that the same as was provided to us in the rate case? And, if so, I thought I would mention that I do have Attachment ADR 9-1 in the Maine Commission Northern or Unitil rate case, Docket 2011-92, which provides a summary of the plan and would seem to track what you were reciting for objectives.

MR. FURINO: Yes. And, I can't confirm, because I haven't reviewed the discovery in that.

MS. MacLENNAN: Right.

MR. FURINO: And, I was probably behind some of that discovery, but not that particular response. So, it could well be that it's that same plan.

MS. MacLENNAN: All right.

MR. FURINO: And, those metrics were laid out. And, those are what are feeding into the spreadsheet that we've been referencing to. And, if you follow on that, the fifth and final piece of that was to seek profitable off-the-main opportunities. And, you know, as we couch it, to try to target 100 percent of what's available that's profitable off the main, and I guess what I'd call a "rule of thumb" value, trying to get three large projects annually. But all of that is constrained by our ability to actually do the construction and get it, you know, get the work done, and customers in place before the construction season ends.

And, as far as cast iron replacement goes, yes, it is definitely a major part of assumptions that are related to the on-the-main aspect of this.

MS. MacLENNAN: Okay.

MR. FURINO: I thought maybe we could look at Tables III-2 and III-3, which show the summary data we were looking at earlier, in terms of planning load. And, again, if you look at the total values -- it's on Page III-12. If you look at the subtotals, where you see on each, I think it's the third column in with data, "SUBTOTAL". It's residential/C&I subtotal. I would call that the "statistical forecast result". And, for Maine, which is on top, Table II, it's 0.3 percent annual growth. For New Hampshire, on the bottom, it's 1.2 percent annual growth. And, then, you've got all these adjustments. And, so, as Jim was saying, you've got energy efficiency, which is reducing sales growth; marketing adjustment, which is increasing sales growth. And, again, this is the planning load component of the marketing adjustment, and the energy efficiency, frankly. There is other energy efficiency and marketing sales increases, marketing-related sales increases that are occurring. But, if you take these and go over to the, you know, right-hand most column, you see that the Maine planning load is projected to grow at 1.5 percent, versus the 0.3 percent, which was the sort of statistical model output. And, I'd probably suggest, so the delta between those is 0 -- well, 1.2. And, you know, part of that is offset by the reduction in sales due to the energy efficiency. So, if it wasn't for that, perhaps the marketing adjustment on its own might be higher than 1.5 percent itself. So, that's really the level of expected new load that we've modeled into the forecast.

MS. MacLENNAN: Could I ask on this schedule -- or, rather, Table III-2, it shows the Maine "Company Use" quantities as "7,141", and the New Hampshire "Company Use" quantity as only "631". Could you explain why that would be -- why there is such a large difference, particularly considering that Unitil's Maine offices are in New Hampshire?

MR. FURINO: Well, for one thing, we did, during this process, learn that we had, I don't know if it was an error, there was a period of time, and we've submitted a revised response to one of our --

MS. MacLENNAN: Oh, I'm sorry.

MR. FURINO: It may have been Staff 1-3, --

MS. MacLENNAN: Okay.

MR. FURINO: -- in the New Hampshire side. Where, essentially, some -- a key piece of data was not being collected for a period of time, and then was reported sort of all at once, which jumped out of the page for Staff, and they brought it to our attention.

MS. MacLENNAN: Would that be Staff 1-6?

MR. FURINO: Well, actually, we did do -- so, actually, in Staff 2-5, we were asked a follow-up to Staff 1-3. And, in the response to 2-5, we provided a corrected page for the New Hampshire company use. And, so, the company use forecast has increased for New Hampshire, from I believe it was "631", to "1970", "1,970". And, I'm going to guess that's still less than what we had projected for --

MS. MacLENNAN: Yes. Thank you. And, can you explain why there would be such a big difference between the jurisdictions?

MR. FURINO: So, Carol, as I understand it, --

MS. MacLENNAN: Yes.

MR. FURINO: -- the Cotton Road Gate Station and the LNG facility both involve heat exchangers that, you know, consume gas, utilize gas. And, so, those numbers are higher. And, at this point, I don't -- those numbers are -- those are measures that are not allocated to the divisions.

MS. MacLENNAN: Shouldn't they be, though? Oh, no. I thought the LNG was considered a peaking unit for both in the resource plan?

MR. WELLS: So, the sendout on -- so, the cost of any gas purchase that flows through Lewiston, the Cotton Road Station, or the Lewiston LNG plant are allocated. However, the Company use that is measured at those stations is Maine -- is accounted for as Maine company use.

MS. MacLENNAN: Okay. That seems to me to be illogical, given that it's part of the function of the units.

MR. WELLS: I can only state what it is that we are doing. I mean, this is, you know, this was the practice that had been in place when we acquired the Company. You know, I don't know what, if any, vetting of the accounting for company use had. I would only note that, to the extent we said, you know, theoretically, "you know, we should allocate some company use between the two divisions, because it pertains to gas supply", it would seem as though that would create some sort of an iterative process for the calculation of the variable allocator. Because it's a volumetric allocator, so you would have to allocate it, and then that allocation would affect the variable allocator. I mean, I don't know if that -- I'm having a difficult time articulating this concept. But, right now, what we do is we have measured company use for both Maine and New Hampshire that affect the -- you know, so we basically add it all up and divide by the total to come up with each state's allocator. If we had company use, which is part of the -- you know, it is, in essence, an independent variable on the variable allocator itself, if some of that had to be allocated, it seems as though there would be some changes to the variable allocator that would need to occur in order to accomplish that.

MS. MacLENNAN: But there's a component of O&M in the Maine CGA, is there not, for gas supply?

MR. WELLS: You mean, for the -- pertaining to the -- yes, there is a component of O&M in the cost of gas that pertains to the operations and maintenance of the LNG plant. That is correct. I don't -- it's not, I mean, I don't -- now we're getting into more of a ratemaking/rate case issue that I wasn't necessarily involved in. But it seems to me that "operations and maintenance" and "company use" could be argued to be different, to be two different things.

MS. MacLENNAN: Yes. And, perhaps -- but what I think the question really is is "whether the heat exchange function of the LNG plant is company use or O&M for the LNG facility?"

MR. WELLS: I would agree that that would be an issue that --

MS. MacLENNAN: Okay. Thank you.

MR. G. SIMMONS: I was just going to add one thing. As I look at this table here on III-12, it is a load-related table. And, so, my thought is, is that, you know, the Company use, putting aside the allocation of the cost, --

MS. MacLENNAN: Right.

MR. G. SIMMONS: -- it does appear that that "7,141" is consumed in Maine. And, so, for load planning purposes, I guess, it should be included. Whether or not it's in -- for cost purposes, whether or not it should be in Maine or New Hampshire, that's something different. But I think the presentation here I think is okay.

MS. BARTOS: And, correct me if I'm --

MS. MacLENNAN: I see your point. And, that's rational.

MR. G. SIMMONS: Okay.

MS. BARTOS: And, correct if I'm wrong, but I think, from the SENDOUT modeling, Maine and New Hampshire is added together for the planning purposes anyway.

MR. G. SIMMONS: Yes.

MS. BARTOS: So, whether this appears in the Maine table or the New Hampshire table, gets added together --

MR. G. SIMMONS: That is correct.

MS. BARTOS: -- from a planning perspective. Thanks.

MS. MacLENNAN: Yes. My brain does jump to the rate effect fairly quickly.

MS. SMITH: Well, no, because that answered, because my question was, again, how the cost allocated, because I forget, you know, going through how the costs are allocated, the company use, if it's all combined together, then allocated out by probably the variable allocator or the fixed allocator?

MR. WELLS: No, the company use affects

the allocator. So, the allocator is determined by sales usage, plus company managed usage, plus company use usage, for each of the two divisions. So, we take those two -- those three elements for each division, add that all together, that gives us a total, and that ends up being the basis for the variable allocator.

The only point I was making is that, if we decided that there's some company use that gets allocated between Maine and New Hampshire, then there's almost a possibility of there being like a circular reference, because it would be in the -- you know, both the numerator and the denominator, if you will, or I guess it would be both part of the, you know, the input and the output. So, I mean, like I said, at this point --

MR. FURINO: Because it's volumetric, and it's not in dollars.

MR. WELLS: Right.

MS. SMITH: Right. So, it's a fairly small number, so, hopefully, it wouldn't change the percentage too much. But, if more of the volume is allocated to Maine, then, ultimately, more of the costs are allocated to Maine. If you add 7,000 versus 1,600, that's ultimately what happens. You know, if that's part of the --

MR. WELLS: Yes.

MS. SMITH: Okay.

MR. ROSENKRANZ: Just so I can catch up, is there one company use and loss factor for Northern Utilities for both divisions or is there a separate company use and loss factor for each division?

MR. WELLS: Separate for each division.

(Brief off-the record discussion ensued regarding whether to take a recess.)

MR. McCLUSKEY: Carol, can I follow up on the discussion that you had with Jim?

MS. MacLENNAN: Please.

MR. McCLUSKEY: Jim, when you were talking about the competition between natural gas and oil, it would seem to me that the -- that the primary factor that separates the recent past from the current period on that issue is the separation of the natural gas and oil prices. In the fairly recent past, obviously, the prices for the two fuels have gone up and down, but they've generally tracked each other fairly closely. What's happened over the last couple of years is that there has been a major separation between oil and natural gas, which is, obviously, affecting the retail competition between the two fuels. Is that something that's reflected in the model, directly or indirectly?

MR. SIMPSON: Nowadays, we always try to include in our models a variable that reflects the relative price of oil and gas. And, for some of our clients, in some circumstances, in some rate classes, that variable works, but not all the time. And, this is one of those instances. And, when you think about it, there's a lot of customer decisions that aren't really directly based on a cold, analytical assessment of the variables of the price of oil versus gas. You know, there's other things factored in there that we just cannot include in the model. And, it includes -- it includes, most of all, people's perception of that price differential. And, certainly, over time, people on one side are or the other, you know, using gas or oil, have understood that the other fuel might be more advantageous at that point in time, but they sort of shrug their shoulders and say "it will all even out in the end." And, generally, that is what has happened. But, since about 2008 or so, there's been this separation that has just not abated. And, so, I think customers more and more are coming to that realization, and that, you know, reflects -- that has to factor in their own sense of risk aversion, the availability of funds to make the conversion, all sorts of things, that just can't be -- can't be modeled in. It's just too complex for modeling purposes.

MR. McCLUSKEY: So, if I can just finish. So, are you saying that it's not reflected in the model? The relative price between oil and natural gas is not reflected, is that what you're saying?

MR. SIMPSON: We tried. We could not get those variables to stick in the Northern Utilities' models, correct.

MR. McCLUSKEY: Thank you.

MR. JORTNER: And, I guess what I was trying to get at before was, that because of this new reality, this new separation, which seems well-established, and not so transitory as prices used to be, doesn't the Company have it within its control to sort of effect that new reality, the mindset of customers, and take affirmative steps to reduce the barriers to conversion? I mean, the Company can decide that, as it used to do, but no longer does.

MR. SIMPSON: You know, I'll defer to Rob, but one of the points that we see with all of our clients is that a real constraint that they have to operate under is that the construction crews available in their service territory have limited capacity. I mean, they can go as hard as they can during the period that the streets are open, that gas utilities can put in new services. And that, amazingly, in this day and time, is one of the important constraints that is holding back, you know, the number of customers that can be converted at any particular point in time. But I defer to Rob.

MR. FURINO: Yes. No. That's consistent. And, you know, just following up on, George, some of your points. I think it's more than just price. I mean, I think, for the first time, customers are really getting the message. We're seeing on the news, seeing in the paper that, you know, this is a domestic supply. You know, what's that? That's just different than what we have been told over the last 30 years, and where oil, the international aspects of the oil market are being. And, also, that it's cleaner, burns cleaner and things like that. And, what can I do to -- you know, if I had the choice between the two, even if they were price neutral, customers may be shifting to where they would favor natural gas over oil for that reason. So, it's a little more dynamic, I think, than just price. But I don't know how you model that, you know, in a statistical model.

MR. ROSENKRANZ: Just one question. I think this would be for Jim Simpson. In your experience of working with other utilities, is this type of out-of-the-model marketing adjustment something that you do commonly? Is this larger or a normal-sized adjustment relative to what you've had to do in other cases to make up for things that aren't being captured in the econometrics?

MR. SIMPSON: I can say that our clients are considering it. And, some are considering it, you know, to the extent that they want to make marketing adjustments. Most of our work -- most of our work is in Massachusetts, for Massachusetts LDCs. And, Massachusetts LDCs have to work under a very restrictive set of rules, in terms of how they develop a forecast for IRP purposes. And, I think it's fair to say that there's a certain reluctance amongst our clients to produce an out-of-market -- an out-of-model marketing adjustment, such as this, just because the regulatory scrutiny is not worth it.

MR. ROSENKRANZ: Well, hasn't the Massachusetts Commission just come out and said "no, you won't do this", in some cases?

MR. SIMPSON: Yeah. I don't think it's been tested under these conditions. But, certainly, the Department has said that they don't want utilities to rely on the Sales and Marketing Departments to, in effect, create the forecast for the first year or the first couple years. But this is -- this is more of a recognizable phenomenon. But, still, nonetheless, I think that in that sort of climate, Massachusetts utilities are reluctant to expend the effort and the additional regulatory complications of dealing with an IRP that has a marketing plan. I think -- I think that conditions are changing in Massachusetts. I think that you might start to see more Massachusetts LDCs considering and maybe including out-of-model marketing adjustments.

MR. ROSENKRANZ: Thank you.

MR. EPLER: Let me also respond to a couple of things that Wayne said. One is, in terms of what's within the range of what the Company can do. The Company, this year, took advantage of the change in weather, and had its crews out and contractors out earlier than the most recent historical period, in terms of actually doing construction. So, we have responded and we saw that as an opportunity.

The other thing is just a consideration to think about, in terms of the kinds of programs that you were mentioning, is there's a lot of other business considerations that are taken into account in looking at programs like that. Such as, when customers move in and out of a particular location that you're looking to invest in an upgrade that may have a long payback, and so on. You know, who pays for that? Who's responsible for that?

So, there are just -- there are complications in that. That it's not just a simple, you know, "can you get the customer to change and increase their load?" There's other business-type considerations and risks involved in making those kinds of decisions.

MR. PATNAUDE: Just a five-minute break?

MR. EPLER: Sure.

(Whereupon a recess was taken at 11:29 a.m. and the Joint Technical Conference resumed at hearing reconvened at 11:43 a.m.)

MR. FURINO: Back on.

MR. McCLUSKEY: Okay?

MR. FURINO: Yes. Thank you.

MR. McCLUSKEY: We're going to switch topics now. I've got a couple of questions about the exchange agreement. And, I want to start with the response to Staff 14. And, I will say that a lot of my questions today, well, probably all could see them in the written discovery that was issued yesterday. We'll get the formal response in the discovery, but I'd still like to have a little bit of back-and-forth on the issue, which the tech session provides, and we don't really get that opportunity through the formal discovery. But 2-14, and, in particular, the response to Part (c). Do you have that?

MR. GULLIVER: Yes.

MR. FURINO: Yes, we do. Thanks.

MR. McCLUSKEY: You do? Okay. The question was, "what supply sources were delivered to Bay State by Northern on a daily basis for the two years referenced in the question?" And, the Company -- the first sentence to the response, "Northern does not have detail on which supplier resource were delivered to Bay State each day." Which, frankly, blew me away. So, the Company is saying that it doesn't know what resources are being delivered? What Northern's resources are being delivered to Bay State on a daily basis?

MR. FURINO: Well, I think we're telling you which supplies we've delivered. What we don't have is we -- all of our monthly supply invoices are by -- we pay them to each of our suppliers, and we don't summarize them or we haven't set up the ability to summarize them by the delivery points at which we receive them. So, to accurately respond on a day-to-day basis. We just haven't structured our data that way. Mind you, we don't make any payments to Bay State. We're paying our other suppliers.

MR. McCLUSKEY: I understand.

MR. FURINO: And, so, we're validating that we did, in fact, receive each day the quantities that we received from each of those suppliers, but we just don't -- we don't track and report by delivery point, by our receipt point. That's the only disconnect.

MR. McCLUSKEY: So, back up a little. You said -- I think you said, by delivery point, you can determine what was received by receipt -- by delivery point -- sorry, not "receipt point", by delivery point you can determine what's received each day, is that correct? You know that?

MR. WELLS: So, what we did in order to respond volumetrically to this is we went back to communications between Northern and Bay State on volumes that were agreed to. And, Ann, if I misspeak, please, please feel free to correct me. But what we don't -- what we don't track, and, frankly, we've never really tracked is, you know, exactly what supply we use to supply at Bay State.

Now, some of that is because due to the fact that supplies can be interchangeable. Within a given month, we can be taking the same supply either to Bay State or to Pleasant Street. And, so, we frankly don't keep track of these types of mid month changes. So, you know, I wish that, you know, I wish I could tell you that we track this stuff on, you know, give you at any level of data that you'd like. But I want to assure you that we are tracking our, you know, our gas supply costs in an appropriate manner, even though we can't reply to this particular data request in the manner that you requested.

Now, I would say that, if really pressed, you know, we could go back invoice-by-invoice over this period and try to retrodetermine, you know, what we ultimately used, each supply contract, in order to either bring deliveries to Bay State or bring deliveries to Pleasant Street, or, for that matter, to any other point. You know, some of this gas -- so, really, when we buy gas, there are really three things that can happen with it. One, is that the gas gets delivered to, you know, Granite, for ultimate delivery to Northern. Two, the gas could be exchanged with Bay State, in which case Bay State would ultimately bring an equivalent amount of supply to Northern. The third thing is we could just sell it off-system. And, so, we don't really track, you know, each molecule back to its supply source. And, so, our accounting systems and our reporting systems and our tracking are just not set up to that level of detail.

Like I said, if really pressed, it isn't as though we couldn't look at an invoice and tell you what, you know, what we used that gas for. By going back, by trying to sort of go back through our records and come up with something that's either correct or very darn close to correct.

So, I got to say, you know, if this is a level of reporting that you'd like to see going forward, you know, maybe we can work to see what we can do in order to support that kind of reporting. But it hasn't been what we have done in the past. And, so, that is really the nature of the why we responded in the way we did.

MR. McCLUSKEY: Okay. Let me try it this way.

MR. G. SIMMONS: Tell me if this is a valid example. There's going to be long haul gas coming up from the Gulf Coast on Tennessee, and then there's going to be some gas coming in at Niagara on Tennessee. And, so, what happens is is those two paths come together, upstream of Massachusetts, I believe that's where they come together, and then both supplies go by, let's say, Mendon. I think Mendon is where we dump gas for Bay

State.

MS. HARTIGAN: We make deliveries to Mendon, which is the interconnect between Algonquin and Tennessee Zone 6, and that gas is transported --

MR. G. SIMMONS: And, so, some of the commingled gas of two supplies gets dropped off there, and then the rest of it goes up to, let's say, Pleasant Street. And, so, I think what we're saying is, is we're not in the habit of saying 400 of one and 600 of the other went to Mendon, and then the remainder went up to Pleasant Street. I think that's what I'm saying to you.

MR. McCLUSKEY: That was not the intent of my question. I understand that there's a daily nomination that applies to both Northern receipts and Bay State receipts. And, I think what you're saying is, "we don't really care where the gas comes from, as long as those nominations are satisfied." And, so, I wasn't -- the purpose of my question was not "are you tracking the molecules?" We were asking, in order to fill that nomination, presumably you have certain contracts dispatched in order to ensure that that quantity is going to be delivered to Bay State. Presumably, that's what you do, is that correct?

MS. HARTIGAN: Yes. Every month,

basically, depending on what the season is, you know, when I set up the gas plan, I do have specific supply that I use to fulfill my end of the exchange. In the winter, there are certain asset management deals, certain pieces that are baseloaded for the whole winter to fulfill the exchange. The Chicago path, the Algonquin Gas, that's baseloaded. Those costs would be fairly easy for us to track, because, that's, you know, the cost of the Chicago city gate, plus variables, to either Tennessee or to Algonquin.

In the winter, sometimes we will increase, you know, increase or decrease, but usually we try to baseload the volumes. In addition to transportation contracts that we have, spot gas might be purchased, you know, and things can change throughout the month.

So, to say that we can't provide the costs, you know, we can provide some of the costs, which -- very easily, you know, because they're very straightforward in an RFP how the gas will be delivered. It would probably be getting down to the granularity of when spot purchases are made for incremental volumes, that type of thing, that we'd have to dig into deeper.

MR. WELLS: Right. You know, the other,

I mean, from an accounting aspect, you know, we don't track, you know, separately gas that went to the exchange versus gas that went to just general system use versus gas that went to back wholesale purchases. So, you know, I think, when we say, you know, something to the effect of "we don't" -- you know, "we're not tracking it", it doesn't mean that we couldn't, you know, come up with some, like Ann said, it isn't that we have no data, we just don't have, you know, complete data by day, as the request, you know, was phrased.

So, I mean, can we -- I mean, can we agree to -- because there are certain supplies that generally, like Ann had mentioned, the Chicago that comes in through Algonquin, they're generally exchanged with Bay State. You know, as everyone, I think, here by now knows, you know, we have no city gates on Algonquin. So, all of those flows are going to be exchanged. So, to the extent that we have like baseload volumes that are easily identifiable as having been delivered to the exchange, would that be satisfactory towards, you know, being responsive to that request?

MR. McCLUSKEY: It might be best for us to just have the conversation about the exchange agreement, and we can then determine what it is we'd like you to respond to, after we've had that conversation.

MR. WELLS: That's fine.

MR. McCLUSKEY: So, put the question on hold for a moment, and we'll just continue the discussion. Bob, I think, had something.

MR. WYATT: I think what we were looking for, from my standpoint, is you have the portfolio of pipeline capacity contracts. And, many of these contracts have multiple delivery points, including delivery points to Bay State city gates. Some are exclusive delivery points to Bay State city gates, and others are exclusive to Northern delivery points. We're trying to get our arms around how the Bay State Exchange Agreement works in relation to these contracts. For instance, what's your utilization of these contracts? You know, this is an exercise where we're evaluating the contracts and what you need for resources. And, we don't see the level of detail of how these contracts are being utilized. Another example would be, we're not sure how much of your Northern capacity on Tennessee you may be delivering on a secondary basis to Bay State city gates. Diverting some of your Northern resources to Bay State.

We have a lot of questions. We don't know any detail as to what gas is flowing to Bay State on which contracts. And, that's important information for us to see how these contracts are being utilized. It's not so much the supply resource itself, it's the capacity, pipeline capacity resource.

MR. McCLUSKEY: Let me see if I can explain our concern, which is difficult when you don't fully understand the issue, which I would be the first one to admit. So, we're kind of taking small steps for the moment on the Exchange Agreement. But the nominated amount, which is agreed on a daily basis, applies to both Bay State and Northern. So, it seems to me, in effect, we could view this nominated amount as part of Northern's total requirements. Because, if it's not met with Northern resources, it's going to be met with Bay State's resources. So, from a volume standpoint. So, the concern -- so, this portion of the total daily requirements for Northern will be met by the Company dispatching some of its supply resources. And, so, the issue to us is, "okay, is it being dispatched economically? Are you using your resources in a way that minimizes the total costs for Northern?" And, so, without the -- without the Exchange Agreement, that's what the investigation would be. Northern has a set of resources. Is it dispatching them each day in order to minimize gas costs? It seems to me the Exchange Agreement just complicates that issue. But, if we can imagine that, so, we have the Exchange Agreement, does -- I think what we're asking ourselves is, does the Exchange Agreement limit the Company's ability to dispatch some of the resources that it has? Does it limit its ability to dispatch some of the low-cost resources? So, if you could just address that question.

MR. FURINO: I can just jump in early. I'll let Fran and Ann come in with details. But, you know, I think we've signaled a couple of times in discovery that the Exchange Agreement allows Northern to utilize its most cost-effective resources. At this point in time, we're trading Tennessee Gas, Tennessee delivered gas, utilizing our Tennessee capacity. And, in exchange, we're getting Portland delivered gas. You know, the gas that we're providing to Bay State has been less expensive reasonably than the gas we're receiving from Portland, that -- from Bay State via Portland. We don't -- we're not into this agreement with the expectation that there's going to be a long-term persistent, one-way advantage that one party is always going to be beating another in terms of average delivered cost to the other party's respective system.

I think it's, you know, as we've

described, the exchange allows us each to deliver supplies to one another's respective systems that are upstream of our own respective systems. So, we use less capacity, we retain more capacity to use in other ways. And, I think one of the questions that came through last night was "what does the word "segment" mean?" And, "how do you segment?" You know, maybe Ann can talk a little bit about how we can do that, and the Exchange Agreement maybe preserves our ability to do that a little bit.

You know, if at some point in time the Exchange Agreement gets to the point where it is, on a long-term basis, is lopsided, where one party is advantaged over the other, it might be the end of the Exchange Agreement, you know, from a longer term perspective.

And, I think we did respond in terms of, you know, "what would we do without the Exchange Agreement?" We do have an enabling agreement, a NAESB Master Agreement with Bay State that, you know, we could buy and sell, respectively, volumes outside of the Exchange Agreement, you know, so that there's alternatives there.

MR. McCLUSKEY: Rob, but we've never made the -- we've never suggested that the Exchange

Agreement is lopsided. In fact, my understanding is -- how it works is it can't be lopsided. My understanding is that volumes, Northern's resources delivered to Bay State, Northern gets the benefit of those low-cost resources. Whereas, and higher cost resources delivered to Northern, high cost Bay State resources delivered to Northern, Bay State picks up those costs. Is that not correct?

MR. FURINO: Yes. That's correct.

MR. McCLUSKEY: That's correct. So, the volumes delivered are the same on both systems. It's just that the resources used to deliver them are different cost. And, so, if Northern is actually using some of its low-cost resources to deliver to Bay State, Northern is receiving the benefit of those lower costs, okay?

(Mr. Furino nodding in the affirmative.)

MR. McCLUSKEY: And, Bay State is getting the higher costs, so it should. That's part of its portfolio. So, to me, there's no lopsidedness in the Agreement. The issue is really just to do with the nominations.

We're asking ourselves, if the nominated amount that's agreed between the two parties is -- let's say it's low, relative to other days. Does that limit Northern's ability to dispatch some of its low-cost resources? That's one question that we have. And, if that's the case, wouldn't it be better to have direct delivery of those low-cost resources to Granite State, rather than to Bay State's delivery points? That's, essentially, we haven't been articulating in our questions, written and verbal, but that's what's behind our scrutiny at the moment. Is there something in the nature of this Agreement that limits the amount that can be accessed by either party? Does that negatively impact the party that happens to have the lowest cost resources?

MR. FURINO: Well, you know, and just at a high level again, you know, and it's hard to think outside of the structure of what, you know, I'm just, you know, familiar with.

MR. McCLUSKEY: Well, maybe --

MR. FURINO: Yes.

MR. McCLUSKEY: -- your colleagues can respond to that. If we could get a response to that, that's kind of what's kind of needling away at us.

MR. FURINO: Yes. Well, what I was going to say is that the volumes that we currently have in the agreement, the 7,000 for the winter period, the 4,200 for the summer period, reflect resources that can be -- are essentially baseload -- baseloaded for the reason that, you know, they can't require us to deliver less than those volumes. And, those volumes reflect the resources that are, you know, that we don't have primary capacity for to Northern's system. So, in the first case, that's a pretty good result. They can't require us to deliver more than that.

MR. McCLUSKEY: Okay.

MR. FURINO: If the volumes are less than that, well, we can always take the extra volumes up to Granite State on a secondary basis, and it's not constrained between the two points, two locations. So, we can do that as well. So, that was -- one of the important aspects is where we drew the line in terms of what the minimum volumes were. And, as you see in the history, we have, from time to time, both agreed, mutually agreed to lower volumes.

Bob and Steve will recall a period during the first year or two of the Exchange Agreement where the rule -- we had not yet entered the Amendment Number 1, which essentially meant that the party, at that time, the party that nominated the higher volume would be the approved volume.

MR. McCLUSKEY: Uh-huh.

MR. FURINO: And, so, at that time, we

were unable -- Northern was unable to get its Washington 10 storage. And, we had favorably priced Washington 10 storage, in Washington 10, and the volumes on the exchange were so high that Bay State was delivering the bulk of our requirements on the north side of our system, and we had to go out and purchase market gas at that time, which was more expensive, to deliver to Bay State. Now, that was a timing difference. Summer injection prices versus winter prices at that time. We did make off-system sales with our Washington 10 gas to preserve that value. And, we approached Bay State and sought that amendment, which allowed that the -- changed it so that the lower nomination required -- requested would be the prevailing nomination. And, we also lowered the minimums or set the minimums to 7,000 at the time. So, that's sort of a high level.

MR. McCLUSKEY: Yes.

MR. FURINO: I can let you guys chime in.

MR. McCLUSKEY: Could I just follow up on your response?

MR. FURINO: Okay.

MR. McCLUSKEY: Because I think it was -- it was responsive to my question. So, you seem to be saying that, provided Northern could access these lower cost resources, through a secondary firm, then there's no harm to it as a result of the Exchange Agreement. If it happens to be constrained, though, then that could be a disadvantage to Northern. Currently, the way the Exchange Agreement is set up, is that what you're saying?

MR. FURINO: Well, what I'm saying is also I think that there's no restrictions that I'm aware of between the systems. When we start talking about -- that's where I'm -- I will always differ to Ann in terms of, you know, restrictions. And, I did see one of your other questions last night, which was, and I think we've had it before, but kind of talking to Tennessee about moving --

MR. McCLUSKEY: Yes. Okay. The delivery points. That's where we're going to go.

MR. FURINO: That's what Bob said to me. Okay.

MR. McCLUSKEY: Okay.

MR. FURINO: And, we have talked to Tennessee in the past about moving delivery points. We did move a number of delivery points when we acquired Northern from Bay State. So, there was a set of points and volumes that were moved between Bay State contracts and Northern contracts. We have also talked to them probably within the last six to eight months about that as well. Our primary issue with them was trying to regain or gain ROFR rights on --

(Court reporter interruption.)

MR. FURINO: Yes. We're trying to gain ROFR rights, that's a "Right of First Refusal". And, we did get that just recently from Tennessee. But we -- I guess I can let, you know, Ann talk about the details about the delivery point conversation.

MR. WYATT: Before we just -- before we go into Ann's explanation, just a clarifying point. On the Bay State exchange, minimum and maximum -- or, the maximum in the winter period, I believe you said was "7,000", is that what it is? Or --

MR. FURINO: That's the minimum.

MR. WYATT: The minimum.

MR. McCLUSKEY: That's the minimum.

MR. WYATT: Seven thousand. And, what is the capacity, I don't recall off the top of my head, that Northern's -- Northern's pipeline capacity that goes to Bay State city gates, if you added up all those MDQs, what does that come to?

MR. ROSENKRANZ: It comes to 6,683.

MR. WYATT: It does?

MR. ROSENKRANZ: Yes.

MR. WYATT: Do you agree with that?

MR. ROSENKRANZ: Data Request OPA 1.4 -- 1-4.

MS. HARTIGAN: That's the Tennessee capacity, correct.

MR. ROSENKRANZ: The Tennessee capacity that cannot be delivered to Pleasant Street?

MS. HARTIGAN: Well, it can be, just it's just not.

MR. ROSENKRANZ: On a primary basis --

MS. HARTIGAN: That's correct.

(Court reporter interruption.)

MR. ROSENKRANZ: So, that -- that number is the amount of Tennessee pipeline capacity that cannot be delivered to Pleasant Street on a primary basis. It has to be delivered to either Agawam, Lawrence, or Mendon?

MS. HARTIGAN: That is correct. If the pipeline --

MR. ROSENKRANZ: Contractually.

MS. HARTIGAN: Contractually, yes. If the pipeline was constrained in Zone 6 to the degree that only primary-to-primary scheduled nominations would flow, that would be correct. Northern would have to take deliveries to the Bay State city gates.

MR. WYATT: Well, that -- let's step back then. The 6,000 whatever --

MR. ROSENKRANZ: 6,683.

MR. WELLS: Okay. Yes.

MR. WYATT: To me, I thought the number of MDQ added up was a number in excess of that for primary delivery points to Bay State? Is that correct or am I missing something? Because it sounds like what your response was, secondary firm deliveries of some of these contracts can get up to Pleasant Street. That's not what I was asking.

MR. WELLS: No. Bob, so, basically, the resources that are deliverable only on a primary firm basis, only Bay State, are portions of the Niagara capacity path, which, in total, is -- which those two aspects are -- total 1,034 dekatherms, right, that's to Lawrence. And, then, the other are portions of the Chicago, the Chicago path. That includes 1,382 to Agawam, and then it ends up being the -- and then there's the 4,211 that's Algonquin.

MS. HARTIGAN: That goes to Mendon.

MR. WELLS: That goes through Mendon,

that's correct.

MR. ROSENKRANZ: Could I -- I think Bob's problem might have to do with the fact that the delivery point MDQs exceed the total contract MDQs. So, if you do it --

MR. WYATT: Yes.

MR. ROSENKRANZ: -- one way and you go to the points, the Bay State points, and add that up, you're going to get a larger number.

MR. WYATT: I understand that.

MR. ROSENKRANZ: What I did is, take the total, and then subtract out the Pleasant Street, to get the numbers that we were talking about.

MR. WYATT: And, that's why I asked MDQ, contract MDQs, that are specific only to Bay State city gates, rather than what used to be referred to "DQLs", or "Daily Quantity Limits".

MR. ROSENKRANZ: Okay. So, the total quantity that's deliverable on a primary basis to Bay State points is a larger number than the 6,600.

MR. WYATT: Yes.

MR. FURINO: And, I was going to suggest it was in the area of 7,900, but I don't have the documentation to point to.

MR. ROSENKRANZ: If you have Data Request OPA 1-4, you were good enough to confirm the numbers on the table --

MR. WELLS: Yes.

MR. ROSENKRANZ: -- that we put in front of you. And, that's what I'm working from. So, I hope that's correct.

MR. WELLS: Right. John, that's correct for the Tennessee. There's also -- we also have two contracts that are -- that are Algonquin. So, if you added all the deliverable capacity, it's 7,878 decatherms. This includes 1,251 decatherms of Algonquin that we just recently renewed, that will be actually coming back to the portfolio as of November; 4,211 decatherms of the Algonquin; 1,034 decatherms of the Niagara; and 1,382 decatherms that -- which is also part of the Chicago path. These four segments total 7,878 decatherms.

MR. WYATT: Okay.

MR. WELLS: Compared to the minimum take in the wintertime of 7,000 decatherms. That having been said, it wouldn't make sense to me that Bay State would ever want us to go below, you know, that if we were to ever ask for 7,878 decatherms, you know, and then rely on bringing every else to Pleasant Street, that Bay State would say "No, we don't think so. We want to keep you from being able to bring that extra 878 decatherms." You know, --

MR. WYATT: I guess one example that I would think of would be, what if market conditions were such that the supply they would have to deliver to Northern, being right now the Washington 10 supply, were priced at that particular point in time at a price that was higher than other alternatives that Bay State has to buy spot deliveries to their city gates. It wouldn't be in their best interest to deliver any more than they absolutely had to or accept any more from Northern, in that example.

MR. WELLS: Well, I would say we just experienced a winter just like that, Bob.

MR. WYATT: Uh-huh.

MR. WELLS: And, we -- you know, for one thing, I think, you know, what we've been doing with them is agreeing, you know, basically, for the year. We've, in essence, been increasing the minimum to 12,000, for most, you know, obviously, there are going to be days when, you know, warm weather, what have you, we might agree mutually to reduce that below that. But, again, for planning purposes, we're going into this coming winter with a

minimum of 12,000 anyway.
MR. WYATT: Uh-huh.
MR. WELLS: And, which is pretty much what we did for this coming winter. So, it's not, you know, I guess I agree that, you know, for that eight -- you know, for that extra 800 decatherms, which, for this past winter also, I would point out that the minimum of 7,000, if you exclude the 1,251, you're below the -- you know, all of our resources that are on a primary basis only deliverable to Bay State would be, in that case, less than what the minimum was. I mean, yeah, we've increased the minimum above, you know, that 7,000, I guess.
I got a couple of thoughts. One would be that, you know, we've already -- we have agreed to higher baseload volumes under the Bay State exchange, to kind of -- that kind of takes that area out of concern away. The second being, I really don't think Bay State worries about, you know, less than -- volumes of less than a thousand, truthfully. I mean, they are a far -- far larger utility than us. You know, and so I just -- I can appreciate why you want to be sure that we're not having resources that are unable to be accessed because of limitations in the Bay State Exchange Agreement. And, I guess we're trying to provide assurances that, based on

the current market, based on our current portfolio, our understanding of their portfolio, that, within this five year planning period, that that's not really a likely scenario.

MR. WYATT: Well, and I appreciate that. It would just be useful for us to be able to see the volumes in the contracts that are being utilized to deliver to the Bay State city gates, to see the utilization of those contracts, what's being used? What, on days that you move, say, 12,000 to Bay State, you're, obviously, using some of your Northern capacity that could go to Northern city gates to deliver to Bay State. But you're getting the cost, the cost of that 12,000 to Northern to the benefit of Northern customers. I understand that.

But, at the same time, some of the gas that you're delivering to Bay State city gates on Northern capacity that could have been used to deliver to Pleasant Street, and you needed additional supply beyond the payment from Bay State, you could be withdrawing some more of your Washington 10 supply that may not be to the best benefit of Northern customers. It's confusing. That's why it would be nice to be able to see more of the detail of how these capacity contracts are being utilized. Just to get -- to be able to put the pieces of the puzzle together, rather than just accept the assurance, which we have accepted. But it would be nice to be able to verify how these contracts are being utilized. And, that's why we -- I think we did reframe the question a little bit in Set 3 of the data requests, to provide some additional information.

MR. ROSENKRANZ: Would it be okay if I jumped in with a question at this time? Because you raised the issue of the Tennessee contracts, --

MR. WYATT: Uh-huh.

MR. ROSENKRANZ: -- and unless there is something you need to follow up with immediately, before we get too far away from that, I'd like to follow up with one of my own questions. It's up to you.

MR. McCLUSKEY: Just to finish up with what Bob was saying. Bob has articulated part of our concern. You don't need to respond to it. Maybe you can just take that into account when you respond to certain of the written discovery questions. Okay.

MR. ROSENKRANZ: Okay. Thank you. This is actually following up on a New Hampshire Staff Question 2-15, you were at 2-14. You had another question where you asked specifically about the Tennessee contracts and the ability to change the delivery points. Is my interpretation of your response to 2- -- New Hampshire Staff 2-15 correct that it would be possible to change the Lawrence capacity, but it would not be possible, acceptable to Tennessee to change Agawam and Mendon, which are further upstream?

MS. HARTIGAN: As for Mendon, the conversations that we had with Tennessee, there is a -- that area of Tennessee's Zone 6 is, according to the engineers at Tennessee, there would be no ability for us to change our primary delivery point from Mendon to Pleasant Street, because there's a part of that area of the grid that is completely oversubscribed and/or fully subscribed. So, --

MR. ROSENKRANZ: So, based on that information -- I'm sorry. But, based on that information, you certainly wouldn't, for peak day design day planning purposes, you wouldn't count on being able to take Mendon gas to Pleasant Street? Is that a reasonable --

MS. HARTIGAN: On every day of the winter, that particular contract is utilized to take deliveries to Mendon, which then is picked up on Algonquin, to go to the Brockton city gate.

MR. ROSENKRANZ: That's not my question.

My question is, if you're doing something different, if you wanted to do something different with that Tennessee capacity, and you didn't have that Algonquin contract, which I'm going to talk about later, there's a discussion that generally you can take the Mendon gas to Haverhill, but I think I'm just -- just wanted to confirm that, that's something, because of your information from Tennessee, is not a reasonable design day assumption?

MS. HARTIGAN: They would not be able to sell us the capacity to Pleasant Street and change the contract itself. On a design day, whether or not we could schedule gas to Pleasant Street, rather than Mendon, there has never been a restriction point in that part of Zone 6 that would prevent us from getting secondary deliveries to Pleasant Street with that contract. The restrictions that we typically see on Tennessee are in Zone 5, on the 200 leg, and now the 300 leg, with all of the shale production, it's pretty much fully constrained. There are rarely restrictions in Zone 6. And, I have never seen one between Mendon and Pleasant Street.

MR. ROSENKRANZ: I mean, if there's --

MR. FURINO: It's almost a question of who's willing to assume the risk. Tennessee is telling us they're not willing to give us that primary to Pleasant

Street. So, that's a risk they don't think they can --

MR. ROSENKRANZ: Okay.

MR. FURINO: You know, we're kind of saying, "hey, we've never seen a restriction there."

MR. ROSENKRANZ: Right. But going back to the world of design day resource planning, --

MR. FURINO: Right.

MR. ROSENKRANZ: -- that's something that you need to take into account. And, the question is, "is that firm on a design day basis?"

MR. FURINO: Right. One of the --

MR. ROSENKRANZ: Your decision would probably have to be "no", right?

MR. FURINO: Right. And, one of the reasons for that would be just simply that Tennessee's ability to maintain pressure on a peak day, especially with generators firing up, with, you know, the potential for limited LNG injections from Repsol and Distrigas, you know, during the winter situation, these are really big concerns for us.

MR. ROSENKRANZ: Okay. Now, Agawam is further west. So, I assume, whatever applies to Mendon, applies to Agawam?

MR. WELLS: Yes.

MR. ROSENKRANZ: If my geography is correct?

MR. WELLS: It is.

MR. ROSENKRANZ: Okay. And, now, what about Lawrence? I mean, Lawrence is right next door. Are they willing to change the point from Lawrence to Pleasant Street?

MR. FURINO: We've had this discussion with them. And, again, like I said, during those discussions, our big focus was on, you know, 41099, that other contract that we wanted to get the local rates for. We have not yet re-engaged them. I believe they would do that. They have told us, though, they -- and, they played this discussion up a little bit where, you know, we have the legacy-type contracts that have been around forever, and they have the delivery points that you multiple delivery points that exceed your contract quantities and all that. And, they tell us that there's benefits to that. We realize that the redundancy is valuable. And that, if we wanted to move it, we'd be looking at a new contract, and it would be just limited to what our contract quantity is, and without the multiple redundancy of delivery points. And, so, you know, if there is no constraint between Lawrence and Haverhill, are we happy enough with primary delivery to Lawrence, and being able to schedule to Pleasant Street with that, without you know any changes -- any other contractual changes?

But we've asked them more -- to be more specific and asked them, "well, okay, if we have to get a new type of agreement, what exactly would we be throwing away in terms of contract rights?" And, we haven't -- we haven't gotten the answer back that says very clearly what those are. That's, from my perspective, where I'm at.

MR. WELLS: So, the --

MR. McCLUSKEY: Could I just follow up on this?

MR. WELLS: Certainly.

MR. McCLUSKEY: It seems to me, in reading your response about these grandfathered delivery points, I'll call it that, that benefits Bay State, rather than Northern. Why would it benefit -- why would that flexibility benefit Northern, as opposed to Bay State?

MR. WELLS: So, I'd like to take that. I think the -- I think one of the challenges that I think we all have right now is that we are dealing with a five year Integrated Resource Plan. That, you know, and the presumption of the Company is that the Bay State exchange will be available and a continuing resource throughout the five year planning period. But I think we all understand that Bay State's contracts on PNGTS come to term the same time Northern's do. And, so, the question really ends up being, what does Northern do if Bay State decides that there's some other way to get gas into their city gates, they can get their own -- you know, they can get their own Tennessee capacity, and that they don't need the -- they don't need the Exchange Agreement anymore, because they don't have Portland. So, this is not, you know, you know, although we understand that this is a -- that that question, you know, it drives questions like "well, why do you want to have capacity to Lawrence?" Well, maybe, in five years, we don't. "Why do we want to have redundant delivery points?" Maybe we don't, when, you know, when we have to -- when Portland and Northern have to make decisions on the PNGTS capacity.

So, I think, in some respects, the parties are talking past one another, because we are focused on the five year planning period in this docket. And, I sense, from some of the questions, that the question is "well, we all realize that who knows what Bay State is going to do with their capacity." And, I'd say this: There's only so much capacity into New England. There's a fair chance that Bay State may continue with it.

They may find that it's something -- it or some equivalent type of resource. I'm not really sure. You know, and so this is, I think, one of the things that we take away, and I think we kind of knew anyway, is that, as we work through this IRP together, and as we, you know, and beyond the IRP, we need to figure out how we supply the system, you know, we need to decide, really, I think from Northern's perspective, continuing the Exchange Agreement would be ideal for us. We're not so sure if it will be ideal for Bay State. It works for both parties right now. And, so, to the question as to "whether or not we should" -- and, I say all this, because the question as to "whether or not what we do with that Lawrence capacity", is very much driven by whether or not the Exchange Agreement exists.

So, to your question, George, like, you know, "what good does it do to have capacity to, you know, Bay State city gate? How does that benefit Northern?" Well, right now, that capacity to Lawrence, you know, ends up being able to displace very expensive capacity at Westbrook or Newington. And, so, I mean, it isn't as though, if we were to ask Tennessee to move that capacity from Lawrence up to Pleasant Street, that all of a sudden we can't count on that particular contract for, you know, to be able to offset system needs at Westbrook or Newington. But, frankly, it's not -- it's not pressing right now, because I know that out till 2019 anyway, I'm going to have Bay State there as a willing exchange partner, because they have got, you know, I know I answered some discovery request about this, about "how much capacity does Bay State have?" It was well in excess of the, you know, 8,000 that we talk about having that is deliverable to their gate on a primary base only -- basis only.

So, you know, as I see it, you know, in the next -- in the next, if I may, in the next IRP, the issues that we have to hit head on are "how do we deal with the Exchange Agreement if it goes away?" "How do we deal with the Exchange Agreement if it continues?" I think we have an understanding that, you know, and these are all good, you know, all good issues. And, I think it's important that we talk about them. But I just -- it's just been my observation that maybe we're, in a sense, talking about different time periods.

MR. WYATT: Fran, and I appreciate that, and I understand where you're coming from. I just, when I think about the Lawrence capacity, --

MR. WELLS: Uh-huh.

MR. WYATT: -- you can delivery secondary firm up to Haverhill or up to Pleasant Street, sounds like you have an opportunity, Tennessee would probably be willing, on some of that capacity that's up in that end of their pipeline, to give you primary firm rights up there, but you lose your grandfathered flexibility that Rob was talking about, of having multiple delivery points.

MR. WELLS: Uh-huh.

MR. WYATT: But that capacity is going right by those delivery points. It seems to me, what's the likelihood of capacity going right by a Bay State city gate, of shifting gas to that city gate on a secondary firm, versus waiting until 2019, when there may be a new power generator that's located up in Salem, which I was reading about in Gas Daily a couple of months ago, as a potential interest. And, all of a sudden the capacity situation on that end of Tennessee is completely different than what it is now.

MR. ROSENKRANZ: Yes. I think it's -- I would say, looking at it from the standpoint of just a prudent management of capacity, if you've got the opportunity to have uninterrupted end-to-end firm primary delivery on a pipeline and fill that gap, that seemed to be -- would seem to be a prudent thing to do. I understand what you're saying, historically, it's worked, and it works with, you know, fits in with the Exchange Agreement. But, to me, those are secondary things. The Exchange Agreement has value to Northern, to the extent that it's filling gaps. If you can eliminate gaps, yes, then the Exchange Agreement might be good. But, it's not -- no longer necessary. So, that's the perspective on it. That's why we're asking the questions.

MR. McCLUSKEY: Or, it might change, if you were to move the Lawrence point up to Pleasant Street, then that might require a change to the Exchange Agreement, but not eliminate it. There's still presumably --

MR. ROSENKRANZ: Might allow you to change. You've got more flexibility in the Exchange Agreement.

MR. McCLUSKEY: That's correct. Yes.

MR. ROSENKRANZ: You can be more than 6,000, but you could take it down to 6,000. You don't need to change it, but you could change it differently. You have more leverage when negotiating with Bay State, because you don't -- they know that you don't have that need to fill in a gap.

And, finally, with what's going on with pipelines, in terms of fights among different parties on delivery priorities, there's always these issues of how you treat secondary deliveries. And, anecdotally, I don't know, maybe this is not -- I mean, anecdotally, my understanding is there have been pipelines that have put on restrictions on a secondary basis, just because they want to be fair to everybody, even if it's not an unrestricted -- even if the physical restrictions are not there, it's easier for them to put on a blanket restriction to say "today we're not taking secondary."

MR. WELLS: I think -- yeah, I think we can take -- I think this has been a valuable dialogue. We can take this input back and talk about it. And, you know, I think you've got a data request that, you know, we think it's probably appropriate to just address it in that response.

MR. McCLUSKEY: Okay. Where are we, in terms of time?

MS. THUNBERG: Well, I was thinking of that. I believe it's almost twenty of 1:00. And, Gary, you had mentioned maybe taking a lunch?

MR. EPLER: Yes. Steve, you want to?

MR. PATNAUDE: Yes.

MR. EPLER: Okay. Seeing as we have -- our other stenographer is here --

MR. McCLUSKEY: What was that, Gary?

MR. EPLER: The other stenographer is here.

MR. McCLUSKEY: Oh, I see.

MR. EPLER: Steve is done.

(Laughter.)

(Whereupon the lunch recess was taken at **12:39 p.m.** and the ***Morning Session Only*** of the Joint Technical Session to resume **under separate cover** so designated as "***Afternoon Session only***".)