STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

January 19, 2017 - 9:53 a.m.
Concord, New Hampshire

RE: **DG 15-033**
NORTHERN UTILITIES, INC.:
2015 Integrated Resource Plan.

PRESENT: Chairman Martin P. Honigberg, Presiding
Commissioner Robert R. Scott
Commissioner Kathryn M. Bailey

Sandy Deno, Clerk

APPEARANCES: **Reptg. Northern Utilities, Inc.:**
Patrick H. Taylor, Esq.

Reptg. PUC Staff:
Alexander F. Speidel, Esq.
Stephen Frink, Asst. Dir./Gas & Water
Al-Azad Iqbal, Gas & Water Division

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

I N D E X

E X H I B I T S

P R O C E E D I N G

CHAIRMAN HONIGBERG: Good morning, everyone. We are here in Docket DG 15-033, which is the Integrated Resource Plan filing by Northern Utilities. We have a recommendation from Staff. We're here for a hearing on the merits.

Before we do anything else, let's take appearances.

MR. TAYLOR: Good morning. Patrick Taylor, on behalf of Northern Utilities, Inc. doing business as Unitil. With me today is Robert Furino, who will be appearing as a witness for the Company today.

MR. SPEIDEL: Good morning, Commissioners. Alexander Speidel, representing the Staff of the Commission. And I have with me Assistant Director Steve Frink of the Gas and Water Division and Utility Analyst Al-Azad Iqbal of the Gas and Water Division.

CHAIRMAN HONIGBERG: All right. How are we proceeding this morning? Mr. Speidel.

MR. SPEIDEL: Yes, Mr. Chairman. We would like to have a joint witness panel of

Mr. Rob Furino of the Company and Mr. Iqbal of the Staff to testify regarding their points of view on the Integrated Resource Plan, and to provide additional answers to questions as they might come from the Bench or from the parties.

CHAIRMAN HONIGBERG: Are there any preliminary matters we need to deal with before the witnesses assume the position?

MR. SPEIDEL: Not to my knowledge, sir.

CHAIRMAN HONIGBERG: All right. Why don't you have the witnesses move over to the witness stand.

(Whereupon ***Robert S. Furino*** and ***Al-Azad Iqbal*** were duly sworn by the Court Reporter.)

CHAIRMAN HONIGBERG: Mr. Taylor.

MR. TAYLOR: Thank you. Before I begin my direct examination of Mr. Furino, it may be useful to mark Exhibit 1, which is the 2015 Integrated Resource Plan that the Company submitted on January 16th, 2015.

(The document, as described, was herewith marked as **Exhibit 1** for identification.)

CHAIRMAN HONIGBERG: You may proceed.

ROBERT S. FURINO, SWORN

AL-AZAD IQBAL, SWORN

DIRECT EXAMINATION

BY MR. TAYLOR:

Q. Mr. Furino, could you please state your full name for the record.

A. (Furino) Robert S. Furino.

Q. And by whom are you employed?

A. (Furino) I am employed by Unitil Service Corp., who provides professional services to the Unitil affiliated distribution companies, including Northern Utilities.

Q. What is your position with the Company?

A. (Furino) I am the Director of Energy Contracts.

Q. And, in that capacity, did you oversee the development and preparation of the Company's Integrated Resource Plan?

A. (Furino) Yes, I did.

Q. Are there any corrections to the Plan that you would like to make for the record at this time?

A. (Furino) No. There are no corrections.

MR. TAYLOR: I have no further

questions. Thanks.

CHAIRMAN HONIGBERG: Mr. Speidel.

BY MR. SPEIDEL:

Q. Mr. Iqbal, could you please state your full name and position at the Commission for the record.

A. (Iqbal) My full name is Al-Azad Iqbal. And I am a Utility Analyst at Gas and Water Division.

Q. And, as part of your responsibilities at the Gas and Water Division, were you the lead analyst responsible for examining the Company's IRP that was marked as "Exhibit 1"?

A. (Iqbal) Yes.

Q. Do you recall filing on January the 9th of 2017 a recommendation to the Commission regarding how this matter should be attended to by the Commission?

A. (Iqbal) Yes.

MR. SPEIDEL: And I would like to request that this document filed on January 9th, Mr. Iqbal's Staff recommendation, be marked as "Exhibit 2"?

CHAIRMAN HONIGBERG: Fair enough.

(The document, as described, was

herewith marked as **Exhibit 2** for identification.)

CHAIRMAN HONIGBERG: You may proceed.

BY MR. SPEIDEL:

Q. Mr. Iqbal, do you have any corrections that you would like to make to Exhibit 2, your recommendation?

A. (Iqbal) Yes, I have one correction. On Page 2, the last sentence, it starts about the effective date. That was -- that is wrong. So, we want to strike that out.

Q. So, you'd like to have the entire sentence that begins "The demand-side management assessment", and ending "changes were enacted", we'd like that entire three-line sentence to be stricken from your recommendation?

A. (Iqbal) Yes.

Q. Does this strike-out change the general overall conclusion of your recommendation related to the advisability of a waiver?

A. (Iqbal) No, it doesn't.

Q. And the waiver in question would be a waiver related to the requirement under the new iteration of the IRP statute that was passed in

2014 that requires a demand-side management assessment for all natural gas utilities, is that correct?

A. (Iqbal) Yes.

Q. Could you provide a little bit of a description as to why you still think a waiver would be appropriate?

A. (Iqbal) I think that we can go -- there are at least a couple or three reasons for that. One is that this Plan is old, two years old, so updating this Plan doesn't make sense at this time, because there all -- all the other elements also change during this two years. So, even if you update one component, it doesn't make that useful, because of the supply-side, all these other resources, and even the energy efficiency scenario also changed because of EERS. Before, there was no EERS, now we have EERS.

So, it would be, if we go forward and update this filing just to address the demand-side management, it will be almost, from an analytical perspective, not that useful, because we need a robust, new plan to address all these changes we have gone through.

The second one, the second reason is that, not only the marketplace changed and regulatory change on our side, there are regulatory change on the Maine side, too. And that is a big issue. And that's why we have another docket which address those allocation issues. And those issues are very important for the planning purpose. Because if you are not assigning capacity to the Company's supplier at least 50 percent, that creates a big range of planning you need to, because there are lots of uncertainty there, and IRP address that.

So, if we update only the demand-side -- demand-side management side, it doesn't address those other issues we, actually, all the other developmental regulatory and market side.

So, that's why we thought that it's better to go for a new IRP than to updating this one.

Q. So, is it fair to say that part of the reason that Staff had recommended quite a while back, and the Commission accepted, the concept of consolidating the allocation investigation -- interstate allocation investigation and this

IRP review proceeding, was that there's a lot of moving parts in Maine and ongoing flux. Would you tend to agree with the perspective that there's still moving parts in Maine, and that issue of allocation hasn't been completely been brought to ground up in that state?

A. (Iqbal) Yes. I totally agree with that, because that's why we -- the allocation issues are now separated from this IRP docket. Because there are some -- still some moving parts on Maine side, there are also still investigating that issue. And that's why we are keeping our option open, just separating the IRP with the allocation issue. So, even as the IRP docket is closed on our side, we can still address the -- sorry -- IRP docket closed on our side, we can still address the allocation issue on the open allocation docket.

Q. So, the, you know, roughly one year eleven month and two week delay in producing a Staff recommendation on the IRP wasn't related to sloth or inability to engage with the issues, it was rather a reflection of the complexities and the allocation investigation that spilled over into this proceeding?

A. (Iqbal) Yes. And I assure you that there are lots of things we did in between, which is not reflected on this particular docket, but on the allocation docket. And, on the allocation docket, we had a consultant, there are lots of material which helped us to understand the whole process and whole scenario. And, so, I would not say that we wasted this long time, but I think that we used that time to develop a very good understanding and recommendation for the other allocation issue. And, because the allocation and planning are not mutually exclusive, we thought that that's a good way to use our time.

Q. Excellent. Thank you very much, Mr. Iqbal. Mr. Furino, regarding the waiver issue for demand-side management, does the Company support Staff's position in principle regarding that request for a waiver from the Commission?

A. (Furino) Yes, indeed.

Q. And I would say that the Company is, in many ways, kind of like a moving party in this as well, in that it's your IRP and that you understand why a waiver would be advisable, correct?

A. (Furino) That's correct. And I completely agree with Mr. Iqbal about the analytical advantages of starting with a clean slate, if you will, in a future IRP.

Q. So, if the Commission were to request today, for instance, the Company supply a letter under RSA 378:38-a, simply requesting that the waiver be granted for that element, you don't foresee, at least in your own role, any difficulties in providing such a letter, is that correct?

A. (Furino) No, I don't. Thank you.

Q. Okay. Any other thoughts on the waiver issue?

A. (Furino) No. Only that, when we file our next Integrated Resource Plan, we'll certainly address the requirements for energy efficiency analysis under the new legislation. And I guess I'll just leave it at that. Thanks.

Q. Okay. So, I have a series of questions regarding the IRP that's presented in Exhibit 1.

How did the demand forecasting presented by the Company within the IRP perform in the last few years? And I'll give you a few subsets of that, and we can go -- I'll show them all at once and then we can go line-by-line.

What were the actual results and how much were they in line with the forecasts? About costs forecasting, customer counts, and significant differences that popped up in the Company's mind when engaging in a review of the results of these different elements of the IRP in light of actual conditions?

And I guess we can start with demand forecasting as a general construct. How did that demand forecast perform?

A. (Furino) Sure. Thank you. So, the demand forecast, we filed it in January 2015, it was developed based on data that was available and information that was available as of the Summer of 2014. And, so, in the time between then and now, the price advantage of natural gas, relative to heating fuel oil, has fallen. So, natural gas is still more affordable than heating fuel, but -- heating oil, but not nearly as much as it was previously.

So, I would point out that the IRP forecast is, you know, primarily used to review future opportunities. So, when we're actually trying to set customer rates on an annual, year-to-year basis in our cost of gas filings, you'll see us coming in with more short-term type forecasts. Whereas the primary purpose of the IRP forecast is to look at an opportunity that may be three years into the future, and where do we think our demands lie.

We recently acquired a portion of the Atlantic Bridge Project. And, in exploring that opportunity, we compared our Resource Plan against our most recent, and it's our 2017 short-term budget forecast. And what we found was that our short-term budget forecast, we strung these out so we could look at them both in the year -- planning year 2019-2020. And the more recent forecast was approximately 6 percent lower than what is reflected in the IRP. And that really reflects the change in natural gas prices, really low fuel oil prices that have occurred since we developed the Resource Plan in 2005 -- '15.

So, yes. And just to conclude for the question on that, I would say that our -- if we were updating this forecast today, it would be lower because of that, that driver. But it's completely understandable why that would have occurred.

I think you next asked about cost. I guess I would say is that the IRP itself did not present any cost information. The IRP really projected a demand forecast, reviewed the Company's existing supply resources, long-term capacity resources, looked at any resource needs, and then put forward the evaluation criteria that the Company would use to review alternative capacity resources. So, we didn't actually say, you know, this is a particular cost. It's more of a planning document, and we try to document our planning process. Now, in our semiannual, now annual cost of gas filings, we're going through and reporting in significant detail on what our actual costs are. So, if that helps explain from that perspective.

As far as customer counts, I took a look recently at our year-end customer counts. And, as of the end of 2016, we're reporting 64,190 customers. This compares, I don't have the exact number in front of me, but to a table in the Executive Summary, which is -- I'll turn to that briefly here. Great. It's Table 1-1. And it reports a projected customer count of "64,822". The actual number that I reported to you is approximately 1 percent lower than that.

So, given the -- given the lower forecast and the less than -- the less advantageous pricing of natural gas relative to heating oil, I would say that performed fairly well, being off by 1 percent two years into the forecast period.

That's all I have on that.

CHAIRMAN HONIGBERG: Why don't you help him out, Mr. Speidel, if there were other categories you wanted him to hit on.

MR. SPEIDEL: No, no. He has.

CHAIRMAN HONIGBERG: Okay.

MR. SPEIDEL: I'm just keeping track. And it was a very comprehensive answer. Thank you, Mr. Furino.

BY MR. SPEIDEL:

Q. There's a specific question that we have regarding an element that's presented, for instance, within Appendix 2.

MR. SPEIDEL: And my apologies to the Commission. This document was produced back in horse-and-buggy days, before the word came down that we ought to have everything Bates stamped. But this is a pretty well-paginated document.

BY MR. SPEIDEL:

Q. It would be one of the rear tabs, Appendix 2, and Page 8 of 9 within Appendix 2. So, I'll give everybody a chance to get to that table. And that's Table A2-17, Appendix 2, Page 8 of 9. And there's a presentation of an item, a column that reads "Alternative Planning Load", and there's a notation here that reads "Alternative Planning Load = System Throughput less Dual Fuel Capability". What is the significance of the alternative planning load and why is it presented? And could you explain a little bit of the thought behind why this is a relevant item?

A. (Furino) Sure. Thank you. There have been some mention about differences between Maine and New Hampshire. Heading into at the time the Company prepared the 2015 Integrated Resource Plan, the rules in New Hampshire were pretty straightforward, that a customer who moves from sales service to delivery service would be assigned capacity relative to 100 percent of the customer's design day demand. In Maine, that rule was 50 percent. So, if a customer was being served by the Company, the Company would be obligated to plan for and provide 100 percent of the customer's requirements. A customer who would move then to a third party supplier, they would take delivery service from the customer, the Company could only assign capacity for the amount of 50 percent of the customer's design day demand.

This delta, this idea that when we serve the customer as a sales service customer, we're planning for and providing 100 percent of the customer's requirement, but could only assign capacity to marketers for 50 percent of the customer's requirement, creates what we were viewing as a "variable planning load". And we defined for the first time, in this Resource Plan, the concept of a long-term planning load and a short-term planning load. The long-term planning load being based on the 50 percent of those customers who might choose delivery service, and the short-term planning load being the other piece, which the Company -- which the first 50 percent that we know we would be able to assign, the Company would be able to assign, the Company knows that it could plan for that. And, because of that certainty, we would consider that, we defined that as a "long-term planning load obligation".

The variable piece, which the Company might or might not be responsible to serve, we refer to as "short-term planning load". So, there are tables in the filing that will show a long-term planning load and a short-term planning load.

The "alternative planning load" was a scenario that reflected the Company's proposal in Maine, and actually the adoption in both states of the Company's proposal in Maine. Although, the significant change, relative to the current rules, were occurring primarily in Maine under the alternative case.

You could see -- you could see actually a comparison of the short-term and long term planning load versus alternative planning load elsewhere in the filing. I can point you to it, if you have interest in looking at that.

In any case, the alternative planning load assumed, as the footnote that Mr. Speidel pointed to, is that it's the entire system throughput less dual fuel, dual fuel capability.

The Company's proposal in Maine, which we filed in May of 2014, we proposed to eliminate capacity-exempt status in Maine. And we propose that the only exception to that would be that a customer who had dual fuel capability, it would do some demonstration process and we would no longer plan for them. So, those were the one exceptions that we made.

So, that would have impacted our forecasting, by making customers who were existing capacity-exempt customers subject to assignment, and any new customers that were projected new C&I customers would no longer be eligible for capacity-exempt status, so that the Company would know then that we could plan for them. And the upshot of it all is that, under the rules that existed when we filed, the long-term planning load was approximately 60 percent of the overall demand on the system for both states. The short-term planning load added another 15 percent to that, so bringing it up to 75 percent. And this alternative planning load would have the Company planning for the vast majority of the demands on the Company's system. So, that was really the thrust behind the alternative planning load.

Ultimately, and we can get there, I'll leave it there, but I can explain what actually happened in Maine relative to our proposal.

Q. So, that actually, Mr. Furino, is a pretty good segue to my next question. And, in terms of the narrative description within the IRP, I would direct interested parties to the V section that has the tab "Planning Load Forecast" at the head of it. And, in particular, I would say V-88, 89, 90, and 91.

There's quite a bit of discussion that the Company has presented regarding developments in Maine on capacity assignment, and also some discussion by Mr. Iqbal and by yourself regarding the fact that things are still in flux in Maine, and it seems to be an ongoing issue of how Maine is resolving its capacity allocation structure.

Could you, as a starting point, just explain as to why changes in Maine are relevant to what we're looking at in New Hampshire in this area?

A. (Furino) Sure. One of the biggest outputs from -- probably the biggest output from the Resource Plan is the Company's planning load, defining what subset of demands of customers on our system the Company is responsible for planning. Then we would know what we need to go out and find resources for, what's the best resource mix to serve that planning load.

The rules that were in place in Maine led to this variable component, this variable aspect of planning load. And it was actually very significant. So, without having some finality on what that would be, the Company's ability to plan was limited to its long-term planning load, as we've defined it here.

I hope that's understood and that makes sense. Do you have follow-ups for me?

Q. Well, yes. So, we have a two-division system, correct, the New Hampshire Division and the Maine Division? And, yet, the Company, for capacity and supply planning purposes, has to look at the system as an undivided whole, isn't that right?

A. (Furino) That's correct. Thank you. Thank you, Alex. So, the Company does manage a common portfolio, and we are dispatching a common set of resources in order to serve the demands of customers in both Maine and New Hampshire. And we believe that is the most efficient approach. And there is an existing cost allocation process. And those costs, the resources that are obtained and how they're obtained are, you know, subject to the review of the Commissions. And the costs allocated are, under the current process, are going to get shared based on relative demand -- relative share of peak day demand, and also based on the relative commodity that each division is using.

So, as it was going to impact the total amount of capacity the Company was going to acquire, whatever incremental pieces of capacity the Company was going to acquire, it was -- it seemed -- it was important to us that, in maintaining Northern's supply planning on an integrated basis, that changes that impact one division would impact the other, so that we would be able to understand, at a Northern level, which is the contracting level and the operational level, what the Company's obligations are.

Q. So, Mr. Furino, what's outstanding in Maine as an ongoing issue to be resolved and what has been resolved? And, if it would be a little bit better to refer to specific written language within the IRP, but it has been a couple years, please feel free to do so. But our understanding is that there are indeed issues that remain to be resolved in how Maine approaches their side of the allocation piece, is that fair to say?

A. (Furino) Yes. So, as far as allocation goes, in the last cost of gas proceeding for this current winter period, the Maine Commission directed that, now that, in their view, and I agree with it, that the retail choice proceeding in Maine has largely been concluded, there's one remaining issue, that they believe it's ripe to revisit cost allocation. So, they're planning to open a cost allocation proceeding in Maine. It's, obviously, you know, we've, in New Hampshire, the cost allocation docket investigation that was parsed out from this proceeding is still ongoing. So, we expect to be in the situation where both divisions, both states, will have an ongoing cost allocation proceeding at some point in 2017.

So, with that, I can review some of the changes, other aspects of the Company's proposal in Maine. One aspect, and this is -- the implementation of this aspect is what remains outstanding up there, is something we call the "capacity ratio". "Capacity ratio" is sort of a theme that was developed -- that we adopted from the electric side, if you're aware of ISO-New England, ISO-New England requires demand, customer suppliers, to pay for, be responsible for a share of the overall capacity in ISO-New England. Well, we took a similar approach. And, particularly, in the current circumstance, the Company has long-term resources beyond Granite, Granite is the Company's affiliated -- affiliately-owned pipeline that serves Northern Utilities. Upstream of Granite, approximately 60 percent of our design day demand is covered by long-term resources, upstream capacity, such as the new piece of Atlantic Bridge capacity that we purchased, and other transportation capacity and storage capacity, as well as a small LNG facility that the Company owns.

So, the idea of a capacity ratio would be to say that, whatever the total capacity in the portfolio is, relative to the system demand, there's some ratio there. Is it 100 percent? Is it greater than 100 percent? Less than 100 percent? When assigning capacity to marketers on behalf of delivery service customers, rather than assigning the absolute 100 percent of what each customer's design day demand is, we now have an adjustment for call this "capacity ratio", that would say, if the Company is short, well, we're going to provide, let's say, 60 percent of that customer's design day demand rather than 100 percent. And that way, sales customers and delivery service customers share equally in the length of the portfolio. How long the portfolio is, how short the portfolio is. So, as it turns out, the Company now has a contract with its affiliate, Granite. That is a seasonal contract. And, during the winter, the volume is 115,000 a day, decatherms a day, and during the summer it's 85,000 decatherms a day. It results in somewhat of a quirky result that the capacity ratio, with respect to Granite, is greater than one. So, Maine's share of the Granite contract is greater than the Maine demand, and the capacity ratio is a little greater than one. I think we calculated it at 1.08.

But, you know, the level of cost

associated with the Granite contract, relative to the upstream capacity portfolio, is pretty small. And the upstream capacity portfolio is more on the order of 60 percent of the overall demands.

So, in any case, it affects the amount of capacity that the Company actually assigns. And we think it was an equitable approach, and that was adopted in Maine, this capacity ratio.

Another thing that changed, at the time we made the filing, pricing of service for both aspects of capacity assignment was indirect. It wasn't -- in Maine, only specific resources were to be assigned to marketers on behalf of delivery service customers. And the price of those resources was actually calculated as a combination of the Company's entire portfolio. So, marketers who get resources that were primarily the Washington 10 storage, which is the biggest asset that we have in the portfolio, and off-system peaking contracts, which would vary from year to year. The pricing that we were providing, we're providing a service, a storage service, the actual pricing of that service differed from our actual cost. Obviously, marketers would use that service when it was cheaper to use that service than the market.

As far as the peaking services we provided, off-system peaking services, this was the Company going out and buying from a third party, making a demand payment for an ability to purchase gas on a daily basis. We would have to declare a monthly price, and let the marketers know that. So that, on any day during a given month in the winter period, they could call on the Company, called "company-managed supply", we have company-managed supply in New Hampshire as well, but the pricing in New Hampshire is, always was, based on actual cost. In New Hampshire, the Company would allocate a little piece of all of the resources in the portfolio and charge the customers directly the actual demand charges. And, if the Company provides a service, the actual gas, company-managed supply, we would charge the actual cost.

In Maine, that wasn't the case. It is the case today. So, that has been changed. That was a big change that became effective November 1st, 2015, with what we call the "Phase 1" portion of the proceeding up in Maine. So, now, all resources are being allocated, and the services being provided are being provided at cost.

Previously, in Maine, what was happening was the Company would have to honor requests for company-managed service on any given day regardless of the price, and we had set -- we were required to, say, set a monthly price. Well, when the local price is below that price, a marketer would never call on that service. When the price was higher, they would call on that service, and we would have to balance out those costs on the backs of our sales service customers, frankly, in both states. It fell into the Company's "cost of gas" and was allocated pursuant to the approved cost allocation methodology. So, that was -- we put that as our highest priority, which is why -- to resolve, which is why that ended up being the Phase 1, the primary Phase 1 issue.

Another piece of this that fell out of the decisions in Phase 1, the Company no longer provides off-system peaking service to marketers. We will release Granite capacity, so that a company can buy -- a marketer can buy their own gas, have it delivered to, say, Westbrook, which is the primary point we require them to deliver to, and they can then -- so, they accept the Granite -- we assign Granite, they accept Granite, we don't buy the gas. So, we are no longer in the position in Maine of purchasing a supply in the market area on a year-to-year basis simply for the purpose of reselling it to a marketer who is serving a customer. And that's actually something that we do in New Hampshire still.

And, so, there are some changes that may have come out of the Maine proceedings that, you know, we may discuss with Staff and look at as opportunities to introduce new changes for New Hampshire. So, in any case, pricing and capacity ratio, I've touched on those.

As far as the Phase 2, the bigger change we were trying to get, or the biggest change was the change from 50 percent to 100 percent. That change has been approved, and approved for effect November 1st, 2019. So, we're now planning -- we consider that to be well within our planning horizon, which was sort of the purpose of the timing of that. So that as, you know, we work through 2017, if we're looking at resources, we now can look at 2019, the Maine Division, 100 percent capacity assignment.

There are a couple of changes, a couple of other pieces. Now, I had said earlier the Company proposed to eliminate capacity-exempt service; that was not accepted. Instead, the Commission made a few rulings with respect to capacity-exempt service.

First, they allowed existing customers, who were capacity-exempt, to remain capacity-exempt, but they are required to install a daily meter. Now, some of the larger customers, certainly, if they were in our largest customer class, they already had a daily meter. But some customers had to, that were smaller than that, had to decide, and there was a timeframe for them to decide, would they install a daily meter? If they don't, they're going to be subject to assignment.

For new customers, any new customer, currently, the rule in New Hampshire is that any new commercial customer can become exempt if they go right to a supplier. In Maine, you're going to have to be 25,000 therms a year of consumption before you can go to the capacity-exempt or you're subject to assignment.

CHAIRMAN HONIGBERG: Mr. Furino, I'm sorry to break your flow, --

WITNESS FURINO: Yes.

CHAIRMAN HONIGBERG: -- but I have no memory of what the question was that you're answering.

MR. SPEIDEL: "What's going on in Maine?"

CHAIRMAN HONIGBERG: Okay. So, a lot of this information about what's going on in New Hampshire is to provide us context, so we understand what's going on in Maine in this one answer to that question?

MR. SPEIDEL: No, the opposite. That

we're asking what's going on in Maine, because it sheds light on ongoing issues that have been flagged within the IRP, and continue to, I think "fester" is a strong word, but continue to develop in the companion proceeding.

Now, if it's a little too much information --

CHAIRMAN HONIGBERG: Well, it may be exactly the right amount of information. But it's impossible to tell where the breaks are in the thoughts as to what I need to get out of that answer.

So, I'm frankly lost at this point. I apologize. It's my lack of understanding of information you guys all know much better than we do, and certainly than I do, I won't speak for the other Commissioners.

If it would be possible for perhaps the two of you to make shorter questions -- or shorter answers to those questions.

MR. SPEIDEL: Sure.

CHAIRMAN HONIGBERG: The questions, in fact, are quite short. But shorter answers to those questions and take smaller bites, --

MR. SPEIDEL: Okay.

CHAIRMAN HONIGBERG: -- I think it will help me, anyway, follow the points you're trying to deliver to us. And I apologize for breaking the flow.

MR. SPEIDEL: Oh, no problem. It's a very technical area, Mr. Chairman. And what I think I can do is let's just get down back to ground, because I think, as far as the IRP is concerned, we can, with the indulgence of Mr. Taylor, I'll just sort of ask a friendly cross question, almost like a redirect.

BY MR. SPEIDEL:

Q. Mr. Furino, there's a lot of technical issues with capacity assignment in Maine that are still ongoing, correct?

A. (Furino) I will say that most have been resolved.

Q. Most have been.

A. (Furino) There's one remaining issue.

Q. And what would that be, in kind of a succinct, plain English sort of way?

A. (Furino) The calculation of the capacity ratio.

Q. Now, is there something going on that the

Office of Public Advocate in Maine, the counterpart of the Office of the Consumer Advocate in New Hampshire, has raised, to your knowledge?

A. (Furino) The Public Advocate in Maine took exception to Northern's calculation of the capacity assignment -- I'm sorry, the capacity ratio. I could explain the differences. But the difference between the Company's calculation and the Public Advocate's proposed calculation was very small from a dollar standpoint. And we believe that the allocation was more of a -- that the Company's approach had better cost causation, better captured the costs and allocated the costs.

MR. SPEIDEL: Thank you. I think what we'll do is we'll leave the remaining technical issues for the companion docket and the hearing in that and recommendations in that.

BY MR. SPEIDEL:

Q. Moving on, Mr. Furino, there is some discussion of potential supply alternatives, and that would be within the section found, there's incremental supply resources, and I think a lot of this would be in Roman sections, basically, V, VI, VII through IX, roughly.

To avoid a lot of involved discussions, are there any big picture events that occurred in the last two years in the supply picture that has required that the Company adjust its thinking from what it presented in the Plan?

A. (Furino) Well, obviously, as the Commission is aware, that Tennessee's Northeast Energy Direct Project is no longer in play. But, no, nothing that has changed. The Company's position or situation at the time of the filing was we had outstanding issues in Maine, and, you know, we have since made small adjustments. Thank you.

Q. Excellent. So, has -- and just a conclusion question, Mr. Furino, have there been any significant changes in your resource portfolio resource presented in Chapter VI since your IRP filing? And, again, you can do it at a very high level.

A. (Furino) Yes. And I will say that, again, the Company has updated its -- has included information about changes to the long-term portfolio in each of its cost of gas filings in order to keep the Commission informed.

But two pieces I would mention, well, two and a half, I would say. We did modify -- we did participate in Portland's C2C Project. And, in so doing, we are increasing our capacity on Portland from 34,000 a day to 40,000 per day, so, an increase of 6,000. As part of that project or following that change, we're also going to be -- we're going to be replacing our Washington 10 storage contract with a Dawn storage contract. The prior contract was for 3.4 Bcf of storage space, underground storage space; the new contract is for 4.0 Bcf of storage. So, that will be located at Dawn.

The other interesting thing about it is that, although it's located in Canada, it will be assignable. And we plan to release a portion of that storage facility, along with the transportation capacity, to retail marketers. Currently, the Company provides access to marketers for their delivery service customers as a company-managed service. They call us, the next day we bring the gas. In the future, they will hold that capacity themselves, storage and transportation, and they will manage it as they see fit.

And, lastly, as I mentioned earlier, the Company acquired 7,500 a day of Atlantic Bridge capacity.

MR. SPEIDEL: Excellent. Thank you very much, Mr. Furino.

Staff has no further direct questions for this witness.

CHAIRMAN HONIGBERG: Commissioner Scott.

CMSR. SCOTT: Thank you.

BY CMSR. SCOTT:

Q. I'll start with more of a technical issue. Early on in your discussion with Attorney Speidel, we talked about the waiver under 378:38-a. I think, and I may have misheard him, I think he was suggesting "if we ask you for a waiver, you know, will you request one, if asked?" My reading of the law is we can only grant a waiver if the utility puts it in writing and asks for it.

So, I guess my question is, do you intend to do that? And, if so, when would we see it?

CHAIRMAN HONIGBERG: Looks like Mr. Taylor is ready to answer that question.

MR. TAYLOR: Sure. We will provide the required written request as soon as possible after the hearing.

CMSR. SCOTT: Okay. Thank you.

BY CMSR. SCOTT:

Q. The other -- now I'll get more esoteric, I guess. I was curious that, first of all, I'll say, even though, obviously, maybe your crystal ball wasn't as clear as some people would like when you filed. I think it was a good effort, and certainly it's put together well, the LCIRP. One of the challenges we have with this process generally with all of the utilities is understanding that it's not just an exercise to fit the statute. You know, it's not just a report, but do you actually use it?

And I guess my question is is, are there things that you would like to do different that we should be looking for that would make it more useful for you? Or is this -- well, I'll start with, is this a tool that you actually use in the management of your Company?

A. (Furino) Actually, and I appreciate the question, it actually is. It's actually a document that we use on a couple levels. We distribute it throughout the Company. Not all -- not all functional areas in the Company are generally aware of what our supply planning activities are. So, we use it for internal communication. Certainly helps, you know, our operational folks, our, you know, pipeline planning folks, our gas control folks. So, we do use it. And we use it as a supply group and a supply team.

And just recently, in looking at this Atlantic Bridge piece, we did follow the process, we did recognize that our forecast was stale, and we did update, but otherwise used the process that's laid out in the IRP.

As far as future ones and changes, you know, we will try to update our Resource Plan as our evaluation thoughts and as different data becomes available to us to reflect our current process and thinking.

Q. Thank you for that. And it gives me some hope that you're actually using it as an internal document, rather than just to meet a statutory requirement. So, that's --

A. (Furino) Yes. We actually have endeavored to, and I can't say that we've been successful in doing it, but to update the forecasts using the same methodology on a regulator basis, like an annual basis. So that, on the year that we file, we have sort of a warm process. I'll say we don't always accomplish that, but we do work toward that.

Q. So, in theory, whatever schedule you have to submit these, since you're actually using it in your plans generally, it should be less of a lift to actually put a plan together for us whenever it's required. Is that a fair statement?

A. (Furino) That's what we've been working toward. Now, obviously, the changes that we are just incurring, and we're still actually in the process of implementing in Maine, really haven't made their way into our working files and that kind of thing, our documents. But that is our approach.

Q. Great. And, in the discussion you had about Maine, I was just curious, talking about capacity assignment and how that all works, is whatever comes out of the allocation docket, given that Granite's under FERC jurisdiction, correct?

A. (Furino) Correct.

Q. Are there -- what's the role of FERC in all that? Is there a role, that they will have to get FERC approval?

A. (Furino) No. There's nothing I see that's FERC approval-related.

CMSR. SCOTT: Good. That may help us then. Okay. Great. I think that's all I have. Thank you.

CHAIRMAN HONIGBERG: Commissioner Bailey.

CMSR. BAILEY: Good morning.

WITNESS FURINO: Good morning.

BY CMSR. BAILEY:

Q. Can you look at Tab VII, which is the "Resource Balance" section, Page 115. No, sorry, Page 117. And I think that this graph shows that the long-term planning load exceeds your capacity for a design day?

A. (Furino) That's right.

Q. Okay. So, in your updates on the projected demand, did this change at all?

A. (Furino) Well, there's quite a gap, right?

Q. Yes.

A. (Furino) So, we have added approximately the 6,000 a day of the C2C capacity and the 7,500 of the Atlantic Bridge. So, that would increase the design day piece -- I'm sorry, would increase the resource piece, the boxes at the bottom, existing capacity.

Q. Right. But it's not going to get it all the way up to the --

A. (Furino) It's not going to get it all the way up, no. The Company still relies on delivered peaking supplies from third parties, which, as we report in our cost of gas proceedings, we purchase those in advance of peak season. And we have a pretty competitive process. But, obviously, it is a long-term planning issue, our approach to that, where we'll be exploring, you know, what is the best peaking resource for the Company, combination of peaking resources for the Company. But this is pointing out, certainly, on a peak day, what that looks like.

You might also look at, I think elsewhere in the filing, we show a load duration curve, which shows more of a dynamic look. This is one day. But it shows so you can maybe see the coldest ten days in a year, you know, how long or short -- how short is the Company.

Q. And, in Section IX, I believe, you say that the Company was exploring construction of peaking facilities. Can you give me an update on your exploration of that? Have you developed any plans for that?

A. (Furino) We haven't developed any plans, any specific plans. We have talked a little bit about particular sites that might be useful. We did share with Staff a feasibility study that we had conducted. Currently, an ongoing proceeding in Maine relates to, if you're aware of Maine's energy cost reduction contract proceedings, where they decided they would support an Access Northeast contract if the other states would similarly support. They have an LNG carve-out docket for that. That's ongoing. And we believe that will be deliberated up there early April. We certainly don't want to spend too much effort with an on-system peaking facility, not knowing if something might be assigned out of that process. But we're participating in that process. Has given us an opportunity to meet with some of the leading developers of LNG facilities in the region. And, as we settle down, just from a Company perspective, would like to resolve the cost allocation issue that remains outstanding and finalize the remaining issue in Maine, and then look toward our next resource, which I believe the biggest need is on the peaking side, and an on-system LNG facility could be the next resource.

Q. And you just said that, I'm not sure I understood you, but it sounded like what you said was that the Maine docket may "assign", "assign a requirement to develop a peaking facility"? Or what did you mean by that?

A. (Furino) Yes. So, a little high-level background on the Maine process. The

Legislature asked or has given authority to the Maine Commission to enter into a contract for a LNG storage facility in Maine, or to direct the utilities to do so.
Q. Okay. And that's the decision that's going to come, you expect, around April of this year?
A. (Furino) Right.
Q. Okay. And, so, they may tell you "build a storage facility", and then that would -- some of the costs would be allocated to New Hampshire customers, but it would address this gap between the capacity and the peak day demand?
A. (Furino) Well, certainly, we would have to reassess what this -- what these, you know, what the Company's remaining resource balance looks like after such a directive.
Q. And how do you plan to incorporate energy efficiency into your next plan? Have you started looking at that? I mean, one of the ways to, I think, address this gap is to reduce demand on peak days. So, what have you done so far in that area?
A. (Furino) Well, my focus area is really on the

supply side. But we are involving and starting to engage our energy efficiency folks, to make sure that we understand certainly the directives that came out of the legislation and other opportunities. We basically are in the process, and what you see reflected in the current filing, is a process that, when the Company comes in for its three-year plan, whatever is approved is base loaded as a resource. So, we certainly accept that as a full resource, reduce our demand by the expected energy efficiency savings, before we begin, you know, planning for incremental resources.

CMSR. BAILEY: Okay. Thank you.

CHAIRMAN HONIGBERG: Commissioner Scott asked most of what I was going to ask. And I appreciated your answers regarding how this planning document is used. I want to ask a question about the least cost component of the statute and the requirement.

BY CHAIRMAN HONIGBERG:

Q. I believe in an answer to Mr. Speidel's questions, you indicated that the Company doesn't do much cost planning. So, I'm wondering, I wanted some confirmation that you're comfortable that what you are doing and the Plan you have in place or the planning process that you follow does produce least cost results for yourself and for your customers?

A. (Furino) Well, I would say, yes. Least cost, and at a reliable, you know, we often use the term "best cost", "most reasonable cost", but, yes. And what I meant to say was we didn't present cost data, but our evaluation approach is meant to find the least cost resource, most reliable least cost. Maybe that it adds diversity at the same cost relative to some alternative. Those are the types of analyses that we do.

We also describe our SENDOUT analysis process, where, by the SENDOUT analysis process, the output of that actually does provide cost data, including unit costs. We can look at, and we describe, we talk about looking at adding a new resource. How does it impact the utilization of our existing resources? And does it -- you know, what's the impact on our average cost?

CHAIRMAN HONIGBERG: Thank you. That's helpful. I have no further questions.

Mr. Taylor, do you have any further questions?

MR. TAYLOR: I do not. Thank you.

CHAIRMAN HONIGBERG: Mr. Speidel, do you have any further questions?

MR. SPEIDEL: No further questions. Thank you.

CHAIRMAN HONIGBERG: All right. I think you gentlemen can stay where you are.

Without objection, we'll strike ID on the two exhibits, and allow the parties to sum up.

Mr. Speidel, why don't you go first.

MR. SPEIDEL: Thank you, Mr. Chairman and Commissioners.

Staff would recommend that the Commission accept the Company's current IRP filing as adequate under the relevant statutory standards, with the *proviso* that the Company will be providing a waiver request regarding the element of demand-side planning resources.

For the reasons described by Mr. Iqbal and Mr. Furino, from an analytical perspective, it wouldn't make much sense for this current planning cycle, which was held hostage to a certain extent by developments in Maine and the need to look at this IRP filing and the allocations issues considered in an investigation in parallel.

We have now recommended and the Commission accepted the recommendation that these two elements and these two proceedings be separated. We think it's time for this IRP to be accepted for the purposes enumerated within the statute as a snapshot in time of the Company's thinking about a number of elements related to its resource planning. It is not perfect, but it is a very good, solid, analytically robust document, and that is what we're always looking for, analytical rigor and analytical consideration and quality information presented for our own consideration and that of the Commission. So, we definitely appreciate the Company making an effort to file this document, and to talk to us about it and to provide data responses regarding its various elements.

We do expect that the next IRP filing that would be made will be responsive to all of the subparts of the new RSA 38 **[**378:38**?]** requirements, and we understand the Company is ready to do that. And, therefore, within the next planning cycle, we think we're going to do a lot more up-front analysis of granular compliance with all those standards.

And we think that the energy efficiency picture, in particular, will be a lot more clear as part of that planning cycle than in this planning cycle. It's been a very challenging time on the energy efficiency side, in terms of the amount of analytical work that has gone into EERS and uncertainties about policy outcomes there. But I think, for the next planning cycle, we'll be in good shape for this one.

So, thank you very much to the Company for its ongoing cooperation and to the Commission for its consideration.

CHAIRMAN HONIGBERG: Thank you,

Mr. Speidel. Mr. Taylor.

MR. TAYLOR: Thank you. The Company appreciates the hard work and the patience of the Staff in resolving this docket. As discussed by Mr. Furino, there were matters that related to the Company's Retail Choice Program in Maine that needed to be worked through. And we appreciate that the Staff and the Commission allowed time for those issues to be worked out. We believe that the resulting changes will have a positive impact on the Company's planning going forward.

The Company requests that the Commission accept as adequate the IRP that the Company filed in this docket, as recommended by the Commission Staff. The IRP meets the statutory criteria of 378:38, subject to the waiver that's been requested by the Staff and that we will follow up with with a written request.

It's consistent with the criteria established in the Settlement approved by the Commission in Docket 11-290. And we recommend -- or, we request that the document be accepted.

So, we appreciate the opportunity to be heard today very much. Thank you.

CHAIRMAN HONIGBERG: Thank you, Mr. Taylor. Thank you all for the presentation and the hard work you've done on this. We'll take the matter under advisement and issue an order as quickly as we can.

(Whereupon the hearing was adjourned at 10:55 a.m.)