STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

March 3, 2010 - 9:13 a.m. DAY 2
Concord, New Hampshire

RE: DE 09-137
UNITIL ENERGY SYSTEMS, INC.:
Petition for Approval of Distributed Energy Resources Investment Proposal and Proposed Tariff. (Hearing regarding Crutchfield Place, Stratham, and Exeter projects)

PRESENT: Commissioner Clifton C. Below, Presiding
Commissioner Amy L. Ignatius

Sandy Deno, Clerk

APPEARANCES: Reptg. Unitil Energy Systems, Inc.:
Gary M. Epler, Esq.

Reptg. Revolution Energy and N.H. Seacoast Energy Partnership:
Clayton Mitchell

Reptg. U.S. Energy Saver, LLC:
Russell Aney

Reptg. N.H. Office of Energy & Planning:
Eric Steltzer

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

APPEARANCES: (C o n t i n u e d)

Reptg. Residential Ratepayers:
Meredith Hatfield, Esq., Consumer Advocate
Stephen Eckberg
Office of Consumer Advocate

Reptg. PUC Staff:
Suzanne G. Amidon, Esq.
George R. McCluskey, Electric Division

I N D E X

E X H I B I T S

P R O C E E D I N G

CMSR. BELOW: Good morning. We'll come out of our recess in DE 09-137. And, in our haste to conclude matters yesterday, I forgot to ask Commissioner Ignatius if she had any questions for the panel. I see George Gantz is the only one who's returned. But I'm wondering if we might -- the Commissioners might have an opportunity to ask some questions, before we move to the Staff's witness.

(Whereupon George R. Gantz was recalled to the stand, having previously been sworn.)

MR. EPLER: Just remind the witness that he's under oath.

CMSR. BELOW: Okay.

CMSR. IGNATIUS: Thank you. Good morning, Mr. Gantz. Welcome back.

WITNESS GANTZ: Good morning.

(Brief off-the-record discussion ensued regarding the microphones.)

GEORGE R. GANTZ, PREVIOUSLY SWORN

BY CMSR. IGNATIUS:

Q. Mr. Gantz, a couple of discussions yesterday seemed to bring about answers that were "well, we thought it made sense. It's the first time we filed this. This is all new territory, and we're still working out how the statute is going to work", which I appreciate. But I'm wondering about as we go forward. For example, Ms. Hatfield asked you about Unitil's strategy for, and, I'm sorry, I didn't pull out the statute yet, "a strategy for minimizing transmission and distribution costs", that language that's in the statute. And, your answer was, you know, "well, we're always looking to that, and this filing is an example of working towards a strategy." Do you anticipate a more formalized strategy going forward?

A. (Gantz) Yes. And, specifically, the Company has, for several years, been discussing internally, and incorporated into the discussions and the thinking behind its strategic planning, about the transformation that we see happening particularly in the distribution business. And, that transformation includes the technology enhancements that was part of our decision-making behind implementing AMI. It was, you know, part of our presentation to the Commission on Time-of-Use rates in the EPAct docket, now reflected in the Time-of-Use pilot. And, as part of that entire strategic thrust, we see the critical importance of DER to the evolution of the distribution business and the evolution in the way energy services are offered to and available to customers.

So, it's a pretty broad-based thinking and a broad-based strategy. And, I think, when we talk about it internally, we talk about it in terms of decades, where this evolution and transformation is going to take place. So, in that, you know, and that's the context I think we're thinking.

Specific to operational aspects of distribution, which, you know, if you take a narrow view of, you know, minimizing the cost of distribution, I think you're sort of looking at distribution from an operational standpoint. I think a direct relationship in DER is in the areas that we've had some questions on in the proceeding, about "All right, well, how is this going to impact, you know, your distribution-related investments or transmission-related costs?" Obviously, the more you can tilt your activity towards demand reduction, the more benefit you're going to get on that side. And, so, that is a key part of our thinking. Looking to DER and other kinds of technology investments that can take place as a way of minimizing future distribution investments and future distribution costs.

But I think it's important to realize that DER also has a broader set of benefits to society in the form of displacing imports of generation. And, so, we're certainly thinking about both sides of that spectrum as we look at the strategy and move forward. Part of the charge to me from the Company senior management, and we've had discussions at the Board level about DER, this year we want to more formalize -- more formally describe the business case for DER and the way it's going to be -- the way the Company is going to engage in those activities. And, then, I think the next step in our thinking is to bring it more formally into the, you know, engineering design and planning aspects of the Company, so that we can make sure that what we're doing, between the DER activities, distribution planning, technology assessment and planning, are as integrated as they can be. So, it's a multiyear process, but that reflects our current thinking.

Q. Do you expect that all of that thinking will find a home in the least cost plan for Unitil?

A. Yes. We've had some discussions about that, and we know there's a, you know, the next iteration of the

electric least cost plan is being worked on now. And, we will have, you know, a description of how DER is going to -- and energy efficiency also is going to interface with distribution planning. At this stage, I wouldn't characterize it as, you know, "comprehensive" or "fully integrated" in any sense, but I think we will address it in that context. And, then, going forward, as our strategy evolves and begins to get more formalized, I think that would be an appropriate mechanism for the Company to communicate with the Commission on that.
Q. Another one of the areas where there was discussion yesterday that you were trying to sort out what was responsive to the statute and took your best shot was in the area of the memorandum of understanding with the partners on the three projects, now down to two projects. The statute calls for an "executed contract or executed agreement". Do you expect those documents to become more detailed in future proceedings?
A. Yes. We're bootstrapping this year and clearly wanted to be able to proceed in this docket and get the guidance from the Commission, in terms of structure, framework, and cost recovery, while minimizing the amount of time and effort and expense that we put into

that process. And, so, we believe that we met the statutory requirement by filing a memorandum of understanding with the participants. But I think the Staff has made clear that, you know, the information and data wasn't detailed enough about structure and risk and who's doing what, to provide for the clarity that we need. So, we certainly recognize going forward, when we do our next round of project proposals, we're going to need to meet that requirement right up front. And, in many cases, if not most cases, it should be in the form of some kind of a contract with a participant or at least a detailed form of contract. And, in other cases, as I indicated, if it's a program where we're going to be soliciting, you know, for example, maybe we'll be putting out, offering something that we will -- we will be asking for solicitations. Where we don't have a contract, because we don't actually have participants yet, we certainly need to make that specific and detailed enough that the Staff and Commission will be able to evaluate it.

Q. Do you have a concern that the partners on these two projects may not fully understand all of the obligations, because it -- the MOU wasn't as detailed as it might have been?

A. I think the discussions that we've had subsequent to the MOUs during the course of this proceeding, I think have clarified those responsibilities, and I think made clear to all the parties where things are at. So, I don't have any concerns at this point. I do agree that the MOUs weren't, you know, didn't provide that level of detail or perhaps that level of certainty about the understandings of the participants. So, that is something we will work on in the future.
Q. Mr. Gantz, I know from other public forums where Unitil has made presentations, that the peak demand days that your system experiences are not that many, but they're big peaks and expensive for you, for the system overall. And, that you have described in other proceedings and public hearings, public presentations, that that's a real goal of yours to bring those down. How do these two projects affect that peak, if at all?
A. Well, they -- PV has a relatively high coincidence with our summer peak. Our summer peak is what's kind of driving system planning at this point. In addition, excuse me, having the micro-turbine now be available to us for dispatch across summer peaks is an important value. So, I think, in those senses, these projects do have a direct contribution to that specific issue.

Q. Do you have any quantification yet of what you would hope to see in that peak reduction?

A. Yes. And, that's reflected in the modeling, in terms of the capacity benefits that are reflected in the cost/benefit analysis, so that captures directly that benefit from the capacity reduction.

Q. And, line losses is another area that these -- the statute calls for as an opportunity that these kinds of projects can help with, and that the Stratham project you've described as having a benefit on line losses. Is there a quantification of that?

A. Yes. The estimation of benefits includes adjustment for average line losses. So, there's a factor in there. I think, based on discussions with our engineering folks, it probably understates the benefits on line losses, because line losses increase as peaks -- as system demand goes up. And, line losses will also be higher at the end, you know, if you displace energy at the end of a circuit, as opposed to the front of the circuit. So, we haven't done a quantification of specifically that. But, in the benefits evaluation, we used average line losses. So, that's a pretty conservative assumption. And, we think, in the line loss area, you know, we're expecting that these will

tend to be more on peak, particularly the PV, and so that will have a benefit, in terms of reducing line losses.
Q. There was also discussion yesterday of what rate impacts we might be seeing as a result of these projects. And, Mr. Axelrod said it was, you know, "we're talking fairly small numbers." But is there a quantification, and apologize if it's in here and I just didn't see it, but is there a quantification of rate impacts as a result these two projects?
A. When we made our initial filing, we did a rate calculation that looked at the impact, the specific rate calculation of implementing all three of the proposed projects as proposed. So, I know that that number is in the record, I don't remember offhand what it is. And, I think the way -- one of the benefits of the RSA 374-G approach, as opposed to the System Benefits Charge approach, is that the cost recovery in rates is going to extend over the lifetime of the investments. So, there's a better matching between costs and benefits as reflected in rates. But it is true that, as a start-up type of activity, there are, you know, there are upfront costs, and there's also the initial cost of, you know, revenue requirement tends to

be higher on the front end of the life-cycle than on the back end of the life-cycle. So, there can be, if you will, a bump in the rate impact on the front end, which hopefully over time is going to be offset by benefits. And, I think it's a consideration for us in terms of the ramp-up. You know, we made the choice to proceed with, you know, a fairly modest level of investment. We don't anticipate trying to ramp that up fast. We would anticipate a sequential annual process of, you know, starting with the level of investment we're looking at this year, which is, you know, will end up being, you know, a little under a half a million dollars. You know, next year, we would hope to perhaps expand that level a bit, and then look at it as sort of a stepwise process. That, over time, as we get better at doing this, and as the projects get better through time, and as we go through this kind of stepwise process going forward, we won't have any rate shock, we won't have a large disparity between the impact in rates and the benefits being experienced. And, over time, we can monitor that. And, in a sense, you have the opportunity to sort of turn, you know, turn the accelerator up or turn it down, depending upon what we sense is, you know, happening in the rates.

We have, I think, I don't know if you want to call it a "benefit", but, because we're at a state now where loads have decreased because of the state of the economy, energy prices have dropped, because of conditions in the world economy and energy markets in general, it, you know, maybe gives us an opportunity to do some of this experimentation, without, you know, significantly impacting ratepayers.

Obviously, there will be a time when this is going to turn around and rates are going to go back up again and energy prices are going to go back up again. And, I think we maybe have an opportunity to learn a little bit more about this process now, when we don't -- when we don't face that immediate impact of increasing energy prices.

Q. Given that the Crutchfield Place project has been withdrawn, and the Stratham project has been redesigned somewhat -- or, did I get that backwards, the SAU and Stratham?

A. No, that's correct.

Q. Could you have prepared and submit an updated summary of rate impacts as a result of these two projects, if they were approved?

A. Yes, we could do that.

CMSR. IGNATIUS: I guess, then, if we could hold that as a reserved exhibit.

CMSR. BELOW: We can do that, as I think that will be "Exhibit 10".

(Exhibit 10 reserved)

CMSR. IGNATIUS: Thank you.

CMSR. BELOW: Yes.

BY CMSR. IGNATIUS:

Q. And, just so that I'm sure I understand, if we talk about a rate impact from those projects, if approved, that would be an incremental cost imposed on rates, as opposed to a net number, am I right?

A. That's the way we did it originally, and that's the way we would do it. So, essentially, what it does is it calculates the rate that, assuming the numbers remain the same and there aren't any changes, what is the rate that would be implemented on day one for that first one year period. And, so, it is fully, you know, all of the costs being reflected in the rate. It doesn't then go on and try and estimate what the first year benefits are, you know, and calculate a net. So, in a sense, it's the worst case, if you will.

Q. All right. You would then assess it against the anticipated benefits?

A. (Witness nodding affirmatively).
Q (By Cmsr. Ignatius:)
CMSR. IGNATIUS: Thank you. No other questions.
CMSR. BELOW: Thank you.
BY CMSR. BELOW:
Q. Is it your belief that the incremental cost of new distribution plant to meet growing loads, particularly, obviously, peak loads, is greater on a per kilowatt basis than the average embedded cost of distribution plant?
A. Yes, I think that is the case. I would want to confirm that that was the result, for example, in the last base rate case, when we did a marginal cost and embedded cost analysis. But I think that's generally going to be the case. The other thing that's true is the transmission and distribution investments will be lumpy. Less so in distribution than in transmission, but you may go for a period of time when you don't need to make any investments, and then all of a sudden you need to make a very large investment. And, so, it can have a lumpy impact through time.
Q. So, I'm trying to understand this. Is part of your concern about looking at alternatives to traditional

distribution plant investment, is part of your concern that, over time, as load continues to grow, presumably, or if load grows, that you'll have to invest more in this lumpy way at different points on different circuits or substations, to have the capacity to deliver to meet the peak load, which, presumably, from what you've said, is based on summer air conditioning loads in particular, that that will tend to raise the average distribution rate, rather than what was once understood to be the case, that growth would tend to lower the cost for everyone, that growth could raise the cost, average cost for everyone?

A. Yes. And, just to add to that, one of the trends that we've seen in our distribution system is a deterioration of load factor, which lends, you know, more evidence to the conclusion that it's, you know, our peaks are being driven by summer air conditioning load. And, people are tending to put in more air conditioning and whole house air conditioning now than they did 10 or 20 years ago. So, our summer peaks are increasing, driving the need for system capacity investments, without a corresponding increase in sales, because the load factor is deteriorating.

Q. Okay. You've referenced the micro-turbine as something that could be dispatched. It would be located, I believe, in a school building, the Exeter High School, is that correct?

A. Yes.

Q. Which, presumably, and, in the description of that project, generally it was represented that the generation from the CHP micro-turbine, combined with the solar there, would usually be used on-site. It would be used to meet the load locally, and not have to be sold under net metering, because the micro-turbine wouldn't qualify for net metering. If it's dispatched in the summertime, say, in July or August, when the school may not be operating, to help meet a peak load condition, how will that energy be accounted for? Will that be used to offset line losses or what?

A. No. It's my understanding that the output of the generation will always be less than the load at the facility. So, it would, for example, if they're not operating the micro-turbine in the summer because they don't have a thermal load, we then call on it to be dispatched, it would offset electric load at the facility at that point in time. So, it would never generate excess energy into the system.

Q. Well, I guess what I'm wondering is, if it happens to

be on a late July summer evening that you have a peak condition or a critical condition, because some other power plants tripped off, and it's 7:00 at night and there's no activity at the school, and the lights aren't even on, I'm just wondering if it's possible that the thing may produce more power? And, I guess, if it just ran the meter backwards, they wouldn't really get any credit for that, but it would have the effect of reducing line losses?
A. I don't know whether the hypothetical you've asked is actual. I would like to consult with Mr. Mitchell to -- oh, he's not here this morning.
Q. Okay.
A. I thought he was going to be here. Again, it's my understanding that the minimum load of the facility is greater than the output of the turbine. So -- and, that the design of the interconnection will be done such that there will be no flow from the micro-turbine into the Company's system. So, in which case, the hypothetical you've posed will never happen.
But, if it were to happen, the, you know, the scenario of accommodating flow into the grid that the Company is not required to compensate the customer for, it simply becomes an offset to line

losses.
Q. Okay. And, with regard to the Stratham project, where you would generate the power and use it to offset line losses, that's a benefit that, in effect, flows to all customers, whether they take their generation supply from you or a competitive supplier, because it will -- would it reduce the -- change the calculation of line loss for all generation takers?
A. Yes.
Q. Okay. And, likewise, everyone would be subject to whatever charge was to recover that cost?
A. Yes.
Q. There's part of a step increase to distribution rates that you proposed, how do you pronounce it? "DERIC" rate?
A. (Witness nodding affirmatively).
Q. With regards to that, I'm not going to ask you for a legal question or opinion, but I do have some observations, and then want to pose a question. When we look at RSA 378:30-a, it seems to state in every sentence a principle, it says "Public utility rates or charges shall not in any manner be based on the cost of construction work in progress." And, then, the next sentence says "At no time shall any rates or charges be

based upon any costs associated with construction work if said construction work is not completed." And, then, it goes on and says "All costs of construction work in progress, including, but not limited to, any costs associated with constructing, owning, maintaining or financing construction work in progress, shall not be included in a utility's rate base nor be allowed as an expense for ratemaking purposes until, and not before, said construction project is actually providing service to consumers."

Now, assuming the Commission interprets that to mean that that would include charges that are estimated, subject to reconciliation, but still charges associated with construction work in progress, and I think that was one of Staff's concern about your proposed DERIC mechanism, that there could be occasions when, based on estimated cost for something that was not fully in service and used and useful, there could be some rate recovery going on, albeit subject to reconciliation. Can you see a way that your proposed mechanism could be modified to ensure that, even based on estimated rates, it could be not imposed for any particular project until such time as that project is in some way recognized as used and useful and in service?

A. Your -- That was a long question, and in the middle of the question you stated "if the Commission determines" --

Q. Right.

A. -- "that this statute means that you cannot even use an estimate that might be -- require a, you know, have dollars collected prior to the in-service date." With that caveat, you know, if the Commission makes that decision, then I think it's clear that the DERIC, as we proposed it, probably wouldn't quite satisfy that criteria. Because of the hypothetical of, you base it on an estimate, the project gets delayed, your estimate was wrong. You know, and given the Commission's hypothetical determination, then I think we would have a problem with satisfying that.

The solution -- potential solution to that would be to make the inclusion of items, investments, or related expenses, in rates be allowed only after a project had been placed into service. So, there would be a, essentially, a delay in the implementation of the rates, to the point in time after the projects had been completed. So, you know, compared to what we had proposed. We had proposed, you know, starting up front with estimates that would course through the course of the year, and bring projects in when they came in and expenses when they came in, that's how the estimate would be based, and then we'd reconcile after-the-fact.

The hypothetical that you proposed could be addressed if you simply delayed by a year the calculation of the DERIC factor, so that it was looking backwards, in terms of what costs were being incorporated, and not looking forward. And, you know that would be, in a sense, equivalent to what we had proposed, if carrying charges or, you know, interest expense related to that lag period were incorporated into the mechanism.

Q. Okay. Thank you.

CMSR. BELOW: Yes.

CMSR. IGNATIUS: Just one question on that, because this is very helpful, because I had misunderstood yesterday what we were talking about.

BY CMSR. IGNATIUS:

Q. I had assumed that the issue of estimates and actuals related to ongoing expenses, but not construction. And, that you had said "nothing would be recovered until projects were used and useful", and because of that very statute, what people commonly call the "Anti-CWIP statute". So, I think I may have misunderstood. Let's be really clear when you talk about estimates and expenses. Are we, on construction alone, and we'll leave all the O&M and other expenses out of it for the moment, construction alone, your proposal would be to begin to collect in rates costs of construction for ongoing work that isn't yet used and useful, and then reconcile later when the actuals are complete?

A. Yes. The DERIC, as proposed, envisioned a forecast for a year that only incorporated a forecast for projects that had been approved by the Commission. But it anticipated that forecast, potentially including projects that had not yet been completed, but for which there was, you know, an expected completion date, and then an estimate of the revenue requirements associated with that in the ensuing months. So, it's a month-by-month calculation. And, our sense was that, since the Company would not be booking actual expenses until the project went into service, we felt that was sufficient to meet the requirements of the statute. Even though the estimates, at the beginning of the year, were, you know, would potentially be, you know, higher or lower based on what actually happened during the course of the year.

So, you know, I think we felt it was sufficient, we proposed it. But, as Commissioner Below pointed out, if the Commission makes the determination that that's not acceptable under the statute, you know, then that would have to be modified. One way of modifying the proposal would be to make that recovery in rates only after-the-fact, and in which case we would suggest that a provision for carrying charges for interest on completed projects not yet included in rates would need to be factored in.

CMSR. IGNATIUS: Thank you.

BY CMSR. BELOW:

Q. I have a question about whether you could provide a document that might be added to Exhibit 10 or made a separate exhibit, but let me first understand something. In Exhibit 6, which is a December 18th filing by Unitil Energy Systems -- Services, I'm sorry, and it had revised schedules, CLC schedules for the three projects, Crutchfield's dropped out, Stratham has been updated by Exhibit 7, SAU 16 Summary Report of the benefits, and I guess the costs, and the benefit/cost ratio is shown there. And, my question is, is that on the same basis as the update you did to Stratham, Exhibit 5, or are there some different assumptions? And, I guess more to the point, what I'm wondering is if you can do the SAU 16 solar project and micro-turbine project in the same format and basis as you did the two schedules on Exhibit 5, and then do a combined schedule that would show for the two projects combined the benefit/cost ratios of both direct and then separately the non-direct benefits, all based on the same common assumptions?

A. Yes. It would take some work to do that, and particularly building a revenue requirements model and making sure we have that right. The SAU 16 project is a bit -- is a bit different in terms of its structure. But, yes, we could do that. And, what that would then provide would be a revenue requirements analysis, consistent with what we did now for Stratham, an updated benefits analysis, and there are a few tweaks that have taken place from December to February that would need to be incorporated in that analysis. You know, we'd need to double check the way that flowed. And, then, also we could show, similar to the way we do now with Stratham, the direct -- separate direct costs and benefits in the top part of the summary and then the non-direct benefits in the lower part of the summary.

So, we could do that. I need to check with our staff and with Dr. Axelrod in terms of the length of time that would be required to do that, but that is -- and, it's a matter of days, not hours and not weeks, but days.

Q. Well, I don't want to introduce a new variable that needs to be subject to additional cross or consideration, but I do think that might be helpful to us.

(Cmsr. Below and Cmsr. Ignatius conferring.)

CMSR. BELOW: Well, it sounds like to get to a good number of the updated rate impact, you kind of need to do something like that anyway. So, I would just sort of -- the only caution I'd say is to try not to introduce any new variables, but I think that would be a helpful thing for the Commission. And, try to either stick with the explicitly stated assumptions in your update that's in Exhibit 5, or, you could, in the alternative, just if there's not significant difference, stick with what you had in your December 18th filing for the SAU 16 project, but still in the same format as the

GRG-2, show the two projects both separately, and then what happens when you combined the two as sort of an aggregate, so that we can see what the benefit/cost ratios would be for the two in combination. Okay?

WITNESS GANTZ: Yes.

CMSR. BELOW: So, we'll add that to Exhibit 10 as a -- well, I think it should be part of the same exhibit, part of the same package there.

So, I think that's all the questions we have. So, you can be excused. And, I'll ask the Staff if they have a witness to call?

MS. AMIDON: Yes, Mr. George McCluskey.

CMSR. BELOW: I'm sorry. And, there was no additional redirect?

MR. EPLER: No, no additional. I would note for the record that Mr. Mitchell has joined us. And, if there was a follow-up on that question, I don't want to delay the record, but --

CMSR. BELOW: Well, let me let Mr. Gantz talk to Mr. Mitchell on the side. And, if they want to update anything that was said, he could come back and report to us if things are different than what Mr. Gantz represented them to be.

MR. EPLER: Okay. Thank you.

CMSR. BELOW: Let's leave it at that.

(Whereupon George R. McCluskey was duly sworn and cautioned by the Court Reporter.)

GEORGE R. McCLUSKEY, SWORN

DIRECT EXAMINATION

BY MS. AMIDON:

Q. Good morning, Mr. McCluskey. Would you please state for the record your name and your employment.

A. And my what?

Q. Your employment. Where you are employed.

A. My name is George McCluskey. I am employed as an analyst in the Electricity Division of the New Hampshire Commission.

Q. Have you testified before this Commission previously?

A. Yes, on many occasions.

Q. And, do you have in front of you the document that was marked for identification as "Exhibit 8"?

A. Yes, I do.

Q. And, could you explain for the record what Exhibit 8 is?

A. Exhibit 8 is my direct testimony in this proceeding, where I analyzed Unitil's DER filing and make recommendations to the Commission.

Q. And, so I understand it, this document was prepared by you?
A. It was.
Q. Do you have any corrections that you want to make to that document today?
A. No, I don't.
Q. Would you briefly summarize your testimony, Mr. McCluskey.
A. Yes. Very briefly. The Company's filing included three components. One was a cost recovery component, the second component was a methodology for evaluating proposed DER projects, and the third escapes me, it will come in a moment, give me a second. Oh, yes. The Company also proposed three actual projects. And, so, the third element addressed Staff's recommendation with regard to the three projects.

With regard to cost recovery, we did not support the Company's proposed cost recovery method. We proposed an alternative one, which we think is consistent with the spirit of the legislation, which is designed to encourage distributed energy resources. And, we think the step adjustment approach for cost recovery, which has been used several times at the Commission, is -- is consistent with base ratemaking and it required recovery of costs through distribution rates, as required by the legislation. We think the step adjustment is consistent with that. It also allows the Company reasonably fast recovery of those costs, hence encourages the Company to make these investments.

And, the second element of the Company's filing, the methodology, we've proposed numerous changes to that methodology. We think the methodology is a critical piece of the Company's filing, because we see the filing as the first of many for this company, and, hopefully, for other electric utilities in the state. And, Staff's goal is to arrive at a methodology, something consistent with how the Company's Default Service filings work. We think we -- we had a settlement in the first Default Service proceeding, which laid out what the Company had to do each time it made a filing for Default Service recovery. And, we want to have the same outcome with regard to distributed energy resources, so we can turn any filing around very quickly, and without a lot of dispute and need for extensive testimony. And, so, that is why we've made several recommendations to come up with a methodology that Staff can live with, and hopefully apply to different types of distributed resources, and, hopefully, that we can apply to other utilities as well.

And, the third element of the Company's filing, the three projects: Staff recommended approval of two, and rejection of one. We would have recommended rejection of -- approval of the Stratham project had the benefit/cost ratio been closer to one. We thought it was far too far away from one to be in the public interest. But Staff is very supportive of this legislation and of the need to invest in distributed energy resources. But we just felt that the project was not sufficiently economic in order to support it.

Q. And, in your testimony, Mr. McCluskey, you did support the Company's proposal to have a two-step process with respect to investment in DER projects, is that correct?

A. Yes, with a very minor condition applied to that.

Q. Regarding the rate of return, what is Staff's position on the Company's proposal to use the cost of capital as reflected in the most recent NHPUC Form 1 Supplement Quarterly Financial and Sales Information filing?

A. In our direct testimony, we opposed that recommendation. But, since then, we've had several

settlement discussions, although we weren't able to arrive at a settlement. Based on those discussions, the additional internal discussions with Staff, we are prepared to adopt the Company's recommendation for the rate of return.
Q. Thank you. What is Staff's response to Mr. Gantz's proposal to collect a carrying charge on its investment for the period from placing the investment in rate base to implementation of the first step?
A. We are opposed to that adjustment. We have recommended a step adjustment approach that has been used in other proceedings in other -- for other utilities and other sectors, utility sectors of the Commission. They, in those proceedings, they didn't have a carrying charge. The effect of the carrying charge is to allow the company to recover the expense of carrying the investment between the time the investment goes into service and the time it goes into rates. Typically, that's referred to as "regulatory lag". Utilities do not, at this Commission, get the benefit of a carrying charge to eliminate regulatory lag. That's part of -- that's one of the costs, one of the risks that New Hampshire base ratemaking places on the utility. And, we are looking for a method that is consistent with the

existing base rate ratemaking and for distribution rates at the Commission. So, we oppose the carrying charge approach.
Q. Thank you. Regarding avoided energy costs, in your testimony you recommended an adjustment to the Synapse avoided energy cost forecast to reflect a change in natural gas prices since that report was issued. Are you standing by that recommendation today?
A. This is a recommendation that we're actually going to reverse our position on this. In preparation for this hearing, I went back and looked at the Synapse report. Unfortunately, the Synapse report is not particularly clear on the natural gas price forecast that they use for long-term energy efficiency projects. However, I've persuaded myself that the natural gas prices that underlie the avoided energy costs are not as high in the Synapse forecast as I had first thought. They are higher than the current Forward Market prices. But the difference between the current Forward Market prices and what I believe are the natural gas prices in the early years of the Synapse forecast is not as great as what I thought. Hence, our concerns with using an unadjusted avoided energy cost are not as great. And, hence, we would be agreeable to using the Synapse

avoided energy costs unadjusted.

Q. Thank you. On the subject of discount rates, a question was raised at yesterday's hearing about the discount rate used by UES in evaluating the Stratham project. Do you have any comment on that?

A. Yes. There was a discussion between myself and Mr. Gantz on the Company, in its evaluation of the Stratham project, that it was using a discount rate of 1.66 to discount the benefits. But, according to Staff, 3.25 percent to discount the costs. When pressed on this issue, Mr. Gantz appeared to indicate that, in fact, they were not using 3.25 for the costs, but something less than that.

So, over yesterday evening, I did a calculation to determine what discount rate they actually used. And, this calculation is actually in an exhibit, or hopefully will become an exhibit.

Q. Well, I want to -- I want to show you this exhibit, and see if this is indeed that you're referring to. The title is "Stratham Project UES Calculation of Discounted Costs". Is this the document you're referring to?

A. That is correct.

Q. And, this was prepared by you?

A. That is correct.
MS. AMIDON: We'd like to mark this for identification. I believe it's -- are we up to Exhibit 11?
CMSR. BELOW: Yes.
MS. AMIDON: Thank you.
(Atty. Amidon distributing documents.)
CMSR. BELOW: So, we'll mark this exhibit as "Exhibit 11" for identification.
(The document, as described, was herewith marked as Exhibit 11 for identification.)
BY MS. AMIDON:
Q. So, would you like to explain what is shown on Exhibit 11, Mr. McCluskey.
A. Yes. What I did was I went to what is Exhibit 5 in this proceeding, and the two schedules on that exhibit. I went to Updated Schedule GRG-1, which is the revenue requirements calculation for the Stratham project. And, that exhibit doesn't show the PV factors, but what it does show is the annual revenue requirements. And, then, it shows the present value of those annual revenue requirements. So, what my exhibit does is it takes the Company's annual revenue requirements, and

then calculates present value factors for each year using a 3.25 percent discount rate, and which produces present value revenue requirements in each year. And, I summed those, and it produces the same cumulative figure that the Company has. And, in fact, each annual present value number is the same as what the Company shows on its schedule. So, clearly, the Company has used, in the calculation of its revenue requirements, a discount rate of 3.25, not 1.66.

Q. And, with respect to the discount rate of 1.66, why do you think that discount rate is inappropriate?

A. Okay. What we've been talking about up to this point is that there's two sides to this benefit/cost equation. You've got costs, which run out over 20 years, and you've got benefits that run out over 20 years. And, if you're going to compare them, you've got to convert them into present value dollars and sum each one up, and compare present value costs against present value revenues. And, my point to this point is that you, regardless of what discount rate you think is appropriate, you have to use the same one for each side. Otherwise, you're going to get a -- you can get some funky results coming out of it.

So, now we're asking the question of,

"is this figure of 1.66 that Staff has used on both sides, is that the appropriate discount rate to use for these types of calculations?" And, what is -- so, we have to talk about "well, what does the discount rate do?" I'll just, first of all, if you use a discount rate of 1.66, it's very close to one. If it's one, there is no discount rate. So, in essence, what you're doing is, you're saying that a dollar that you receive in year 20 is the same value of a dollar that you have today, which, clearly, economically makes no sense. Because you could invest the dollar that you receive today, and hopefully end up with the dollar in year 20, plus the return on your investment.

So, the closer the discount rate gets to one, you're effectively saying that "dollars expended in year 20 or in year 19 are very much the same as dollars expended in year 1 or 2." And, the Company -- remember that these projects are an alternative to doing traditional T&D investment. And, if the Company were to do a T&D investment, it would demand its -- not "demand", it would request a reasonable return on that investment, and the Commission would determine what the appropriate rate is. And, in the last rate case, the Commission has approved an overall cost of capital, when adjusted for taxes, at the level of 11.45 percent. So, that's the opportunity that the Company has to invest with -- in T&D. So, to me, the appropriate discount rate is the opportunity cost that the Company has in making some alternative investment to doing DER. And, that would be the overall cost of capital, adjusted for taxes, less inflation. We'd need to use the real discount rate, which is 1.66, by the way, but it's a nominal rate, less the inflation rate.

So, I would argue that the appropriate rate to use for discounting in these calculations is the Company's overall cost of capital. And, why is this important? If you use the same rate on both sides, you could ask the question "well, doesn't it" -- "doesn't it net out?" The reason it's important is that the profile of the flow of costs, annual costs, is different from the flow of the benefits. It's well known, with regard to utility revenue requirements, that the revenue requirements are front-loaded. They're higher in the early years, and they drop off as the investment depreciates and the return declines, falls off.

The benefits for these projects might actually increase if, say, avoided energy costs were to

-- the expectation was avoided energy costs were to go up over time or the costs of CO2 allowances were to go up over time. So, you could actually have a situation where the benefits are rising over time, but the stream of revenue requirements are declining. The discount rate, the discounting of those takes that into account. It will -- it will value less the high benefits and value more the high costs in the early years. So, I think it's important to have an appropriate discount rate in order to not favor one type of project over the other.

Q. Thank you. And, as you stated, and correct me if I'm wrong, using the same discount rate for both the costs and benefits side is important to get an accurate analysis, is that correct? Or, do you want to amplify that, say anything more about that?

A. That is critical. Regardless of what discount rate the Commission decides is appropriate, it should be applied equally with regard to the development of costs or benefits.

Q. Thank you. Now, for today's hearing, you prepared a new analysis of the Stratham Solar PV Facility. And, I just want to show you this document. Is this the updated analysis that you prepared?

A. Well, first of all, we need to mention that I filed --
Q. Do you want to talk about that first?
A. That's correct.
Q. All right. I will leave this here for you then. Exhibit 9 is -- represented an updated analysis prepared by you -- well, strike that. Why don't -- And, Mr. McCluskey, do you have Exhibit 9 in front of you?
A. That's what I'm looking for. Just give me a moment. Yes, I do.
Q. Could you tell me what that is please?
A. What Exhibit 9 does, in --
Q. Was it prepared by you, Mr. McCluskey?
A. It was. That's correct. In the Company's rebuttal testimony, the Company restructured the Stratham project. So, my economic evaluation with the Stratham project in my direct testimony was in reference to the original structure of that project. The Company proposed a redesign of the project, which, in most respects, we are very supportive of, we think that was the right thing to do, to bring it in front of the meter and not have it behind the meter, produced significantly more benefits. And, what this exhibit does is provide Staff's economic evaluation of that

restructured Stratham project.
Q. Was that the first time that you had a chance to respond to the rebuttal testimony and to re-evaluate the restructured project?
A. The procedural schedule didn't provide for Staff to submit testimony in response to the rebuttal. But we just felt that, since this issue was likely to come up in the hearing, that it would be useful to have Staff's evaluation of that project out there for everyone to review prior to the hearing.
Q. And, do you have any changes or corrections to that?
A. Yes, I do.
Q. And, if you look at the document that I placed in front of you earlier, does that represent -- it's entitled "Stratham Solar PV Facility Total Resource Cost Test 20 Year Analysis". Is this the one that you prepared for today's hearing?
A. That's correct.
MS. AMIDON: Can I have this marked for identification as -- I think we're up to Exhibit 12?
CMSR. BELOW: Yes.
CMSR. IGNATIUS: And, can I ask just for a clarification? You just said that this was "changes to or corrections to what was submitted as Exhibit 9." Do

you mean that? Or, changes based on further information that's come forward?

WITNESS McCLUSKEY: No, I think it's accurate. We submitted our evaluation in Exhibit 9. And, then, we received the Company's revised evaluation of that project. And, so, obviously, I started to compare the numbers in that revision to what I filed, and asking why there were certain differences. And, as a result of that review of the Company's revised schedules, I found that I had inadvertently used some incorrect cells when doing the calculations. And, so, I'm going to explain which changes are made and what effect it has on Staff's view of the economics or the cost-effectiveness of this project.

CMSR. BELOW: So, we'll mark this document as "Exhibit 12" for identification purposes.

(The document, as described, was herewith marked as Exhibit 12 for identification.)

BY MS. AMIDON:

Q. And, so, Mr. McCluskey, please proceed with the summary of your economic evaluation of the Stratham project as restructured by the Company.

A. Okay. So, very quickly, the summary page from Exhibit 9 indicated a benefit/cost ratio for the restructured Stratham project equal to 0.65. As a result of my additional review, I determined that, when I calculated the revenue requirements and when I was calculating the return component, I used the end-of-year rate base, instead of the average rate base. So, that needed to be corrected. Also, because the Company gets to recover in its rates the depreciation on the project, I actually inadvertently picked up the tax-adjusted depreciation instead of the straight depreciation. And, so, that needed to be corrected. So, both of those errors, if that's what you want to call them, when corrected, had the effect of increasing the revenue requirements. And, you will see that reflected in the revised exhibit, which is Exhibit what?

Q. Twelve.

A. Exhibit 12. Then, with regard to the benefits, I've stated today that Staff is agreeable to using the Synapse avoided energy costs unadjusted. So, I reflected the changes to the avoided energy costs, which also required a change to the item called "Energy DRIPE". That also needed to be adjusted, in agreeing to use the avoided energy costs unadjusted.

The last change related to the REC

component of the benefits. If you'll recall yesterday, there was a conversation as to whether the Synapse avoided energy costs included an allowance for REC costs that utilities would incur if they did not do this type of investment. And, I believe Mr. Gantz agreed that he thought that was in there, and I certainly agree with that, based on my reading of the Synapse report. And, so, because this project is what's called a "in-front-of-the-meter project", one of the two REC benefits that have been discussed in this proceeding, in this hearing, is not available to the Company if it's in front of the meter. If it was behind the meter, like it was under the original proposal, it would have been two REC benefits. Because it's in front of the meter, one of the REC benefits goes. The Company already has and Staff already has a line item for the second REC benefit. So, we have to subtract the estimated REC benefits that are reflected in the avoided energy costs. And, that's what I've done. I'm now showing a REC value of $32,000. Whereas, I was showing 52,000. The $20,000 difference is my estimate of the REC benefits that are reflected in the avoided energy costs, in the Synapse avoided energy costs. So, that's the last change to this analysis. And, the net effect is to reduce the benefit/cost ratio to 0.56, from 0.65.

Q. Thank you. What capacity factor did you use in that analysis for the Stratham project?

A. My analysis used the capacity factor of 13.5 percent.

Q. And, will you please explain the origin or the reason that you're using 13.5 percent?

A. Yes. Again, there was some discussion on this issue yesterday. The NREL, in their report, that was picked up by Standard & Poor's, stated that, on average, existing solar PV facilities in the northeastern portion of the United States have capacity factors equal to 13.5, significantly lower than capacity factors in Texas or in California. So, in my initial calculations, I used 13.5. I generally don't like using numbers reported by someone else without checking them. I attempted to get access to the NREL database, and I wasn't able to do that. However, there is a website that's called "Fat Spaniel", believe it or not. And, they have, I don't believe every PV project, but PV projects that provide data to Fat Spaniel, I don't know whether money changes hands. But many existing PV facilities provide data to Fat Spaniel, who then report it on their website. Not all of the projects provide the data that will allow you to calculate the capacity factor, but many of them do. And, what I did was, I picked out of the data the projects, not in the Northeast, but actually in New England, and that information is shown on a exhibit.

Q. Yes. This is an exhibit that the top says "Solar PV Projects in New England", and the asterisk leads you to an item that says "Fat Spaniel Technologies". Is this the document that you're referring to where you collected information on the capacity factor of New England?

A. That's correct.

MS. AMIDON: I would ask that this be marked for identification as "Exhibit 13".

CMSR. BELOW: It will be so marked.

(The document, as described, was herewith marked as Exhibit 13 for identification.)

BY MS. AMIDON:

Q. So, Mr. McCluskey, what does this, the information on Exhibit 13, tell you?

A. Okay. Well, first of all, in New England, I know there are many, many more operating PV facilities than are shown here, indicating that Fat Spaniel doesn't have access to all of the data. Two, there are many facilities that are on the Fat Spaniel website that don't have the information that I was looking for, and I just got to the point where I didn't add those to this spreadsheet. So, the ones that I did add that didn't have the data I actually show as "not available", that the data is not available that would allow me to calculate the capacity factor. For those where it is available, you will see a column, two columns at the far right, "Capacity Factor" and "Weighted Capacity Factor". The "weighted" is weighted by the rated design capacity of the facilities. You will see that there are many projects that are very small, 2 kilowatts, 3 kilowatts, many of them which are located in schools. And, then, you would see some projects that are more of the size of the Stratham and the SAU 16 projects, some of which are larger than that.

So, what I've calculated is an average capacity factor weighted for facilities that are greater than 10 kilowatts and for all facilities that are shown here. And, you'll see that the weighted average is, in both cases, is just over 13 percent. Which is less than what I'm using, but I think it's generally supportive of the figure that I've used to do these calculations.

And, just to finish on this issue, the importance of the capacity factor, why are we spending time discussing this issue? In this economic evaluation, because we have avoided energy costs as one of the benefits, if you use a capacity factor for the PV facilities that is unrealistically high, then you increase the avoided energy costs. You also increase what's called "Energy DRIPE". And, also, you increase any benefits associated with CO_2, which you might have in the calculation. So, if you use a capacity factor that is considered unrealistically high, you can change the benefit/cost ratio inappropriately. So, it's important I think that we have realistic capacity factors, and, hence, that's why we're having this debate as to what the appropriate number is.

Q. Thank you. Earlier, Mr. McCluskey, you mentioned that your Exhibit 12, the corrected evaluation of the Stratham project, included some recalculation of the REC benefits. And, in connection, for the REC benefits, did you prepare an analysis of the Company's evaluation of REC costs going forward 20 years?

A. Yes, I did. I tried to, because we didn't get the

Company's analysis in Excel format, we couldn't actually see the formulas and annual prices underlying their REC benefit of 133,000. So, here, in this analysis, I'm attempting to reproduce that benefit.

Q. And, I'm going to show you a document, it's entitled "Stratham Solar PV Facility 20 Year REC Benefit UES Analysis". Is this the analysis that you prepared?

A. That's correct.

MS. AMIDON: Thank you. I'd like to mark this for identification as "Exhibit 14".

CMSR. BELOW: It is so marked.

(The document, as described, was herewith marked as Exhibit 14 for identification.)

BY MS. AMIDON:

Q. Could you explain what is shown on Exhibit 14.

A. Yes. As I said, I'm trying to reproduce the Company's number of $133,000 present value. And, what we have in the first column is a calculation of what -- of the expected ACP in each year. The escalation rate came from some previous exhibit. I don't recall exactly where that number came from. But that's what we're attempting to do here, just forecast what the ACP is. The second column, based on the Company's approach, is to estimate a REC price each year, which is equal to 75 percent of the ACP. The "Load Reduction", the ACP applies to load reduction, rather than demand reduction. And, so, the estimated prices each year would be multiplied by the 52 megawatt-hours that the Company has assumed would be the load reduction as a result of this Stratham project. So, the next column calculates the "REC cost" in each year associated with this project. And, the next column gives the "PV Factor", based on a 3.25 discount rate. And, the last column gives the discounted REC cost. And, when you sum up the annual amounts, it came to 134,000, which is not equal to 133, but I believe is close to it.

And, so, I'm concluding from this that, in order to arrive at a REC benefit, 20 year REC benefit of 133,000, the Company had to have a REC price, in year one, of roughly $125 and, in year 20, $262.

Q. And, do you -- are you aware of what the market price is for Class I RECs currently?

A. It would be Class II.

Q. Class II.

A. We're talking about solar PV, so it would be Class II.

Q. Thank you.

A. And, the figure of $50 to $60 comes to mind. I forget what the actual rate is at the moment.
Q. I think that you're in the right ballpark.
A. Okay.
Q. You mentioned earlier that the Synapse study includes avoided REC compliance or RPS compliance costs and the avoided energy costs, is that correct?
A. That's correct.
Q. And, you're looking at the -- I'm going to show you a document here. And, if you could tell me the source of this document, and tell me what the heading is?
A. Well, this document is actually a page from the Synapse report. It's Appendix C to the Synapse 2009 report, and it's Page -- as it shows, Page C-12.
Q. And, what does the heading read?
A. It's "Appendix C-12: Class I REC prices and avoided RPS Costs by New England State".
Q. Thank you.
A. And, I'd just like to, it says "Class I". However, when you look -- when you read the report, Synapse defines what it means by "Class I". And, they defined "Class I", as used here, to be both Class I and Class II. And, they specifically state in the report that their estimation of what it's determined as Class I

includes New Hampshire Class II RECs. So, this column that is headed -- oh, you don't have the exhibit.

MS. AMIDON: Right. I would like to mark this document for identification as "Exhibit 15".

CMSR. BELOW: It's so marked.

MS. AMIDON: Thank you.

(The document, as described, was herewith marked as Exhibit 15 for identification.)

BY MS. AMIDON:

Q. What does Exhibit 15 tell you with respect to the estimated value that the Company used for the REC costs going forward?

A. Well, the appropriate column to be looking at is -- it's headed "New Hampshire", in the first block. So, it's what, the fifth column over. And, these prices are in 2009 dollars. It's important to recognize that. So, it has -- it shows Synapse's projections of REC prices over time. Because this projection relates to both Class I and II, it's not a perfect match for what we're discussing here. It's a combination of two different classes. But I think it's interesting that the results of their analysis, and their analysis was to do a detailed supply/demand evaluation for RECs in the New England states over the long term. And, based on that supply/demand evaluation, they see Class -- the combination of Class I and Class II REC prices, not rising in time, in real dollars, but actually falling quite significantly over time. So, this trend is considerably different from the trend that the Company had, and also the trend that Staff used to calculate its $52,000 of REC benefits in its initial filing.

Staff assumed that it would rise from the existing level at the rate that the ACP rose. And, the Company assumed it would rise at the same rate, but starting from a higher level. Here, Synapse appears to be indicating that the supply of RECs is likely going to outstrip the demand for RECs over time, and, hence, the prices are going to fall. That's my interpretation of what these numbers are showing.

Q. Thank you. The statute, RSA 374-G, has a number of criteria that the Commission must balance to determine whether there's public interest in proceeding with a distributed energy resource project. Three of these criteria in RSA 374-G:5, II, (a), (c), and (d), requires three benefit/cost analyses to be conducted when evaluating whether a DER project is in the public interest. And, did you conduct this analysis when you

reviewed the Stratham and the SAU 16 projects?
A. Yes. In Staff's direct testimony, for each of the three projects that were proposed, Staff did what's called a "Total Resource Cost Analysis". Then, we factored the basis. We then did an analysis, which just looked at how the participants in the project fared. And, then, we did an analysis on how the non-participants, the general body of ratepayers, fared in the project. So, for each project, we did three analyses. And, we think those are the analyses that the legislation was referring to.
Q. Another criteria in that list of considerations is that the Commission consider the "environmental benefits" of the distributed energy resource investment. Did you take environmental benefits into account in performing your evaluation of these projects?
A. Yes. There was testimony yesterday that Staff didn't consider the environmental benefits under the benefits, which has -- reflects a misunderstanding of the calculations that we did. The Total Resource Cost Test include benefits for avoided CO2 costs, avoided SO2 and NOx allowance costs, which are reflected in the avoided energy costs, avoided REC costs, and the receipt of federal tax credits associated with renewable projects.

None of those benefits would be included in a economic evaluation, if we weren't dealing with renewable projects.

So, recognizing that they had put forward renewable projects, which have considerable environmental benefits, which are being recognized by things like REC costs, Staff worked those benefits, not from a qualitative standpoint into its analysis, but from a quantitative standpoint. So, I would say Staff very carefully included every environmental benefit that we could think of that was appropriate to include in those analyses. So, I would dispute that we didn't take environmental benefits into account.

Q. And, in fact, Mr. McCluskey, you observed that there would be Forward Capacity Market benefits that the Company hadn't claimed, and they modified their model to include those, is that correct?

A. They did. But the avoided capacity market costs is not a benefit associated with environmental benefits. It's a benefit associated with reliability, which I believe we're going to address next.

Q. Well, and I was going to that. That's another criteria which the Commission must consider, in balance with the other criteria, to reach a public interest finding,

reliability. Did you evaluate reliability in the context of reviewing these projects?
A. We did. If the DER projects are not reliable, then they would not be able to claim that they avoided generation capacity costs, nor avoid T&D capacity costs. The fact that, in our analysis, we've included the full benefit of avoided capacity costs and avoided T&D in the analysis, indicates that, at least from a modeling standpoint, Staff assumed that these projects are highly reliable.
Now, it may be that the ISO, in practice, does not consider PV facilities to be 100 percent reliable, and, hence, may not give them the benefits that we have included in our analysis. But, at least from a modeling standpoint, we've assumed that they are highly reliable, and, hence, included the full amount of the avoided benefit.
Q. Thank you. Did you also take into account economic development benefits in your analysis of these projects?
A. No, because we were not persuaded that there were any significant economic development benefits associated with the -- at least with the Stratham project.
Q. In other words, you considered the issue of economic

development benefits, but you found none? Is that a better way of saying it, than you did not consider economic development benefits at all?

A. That's correct.

Q. You looked at it and found none?

A. That's correct. There's kind of three components to our analysis. The first one, with regard to Stratham, the Company hasn't yet issued the RFP. So, we don't know who's going to install and acquire the equipment and where from. So, it's a little early to be claiming economic development benefits for a project that may actually be manufactured in China or in Arizona, and, hence, the component of the estimated capital cost may actually be spent out-of-state, rather than in-state. So, that's the first one. We don't know who's going to do this project.

Secondly, on the assumption, if we leave aside the fact that an RFP hasn't been issued, testimony was given yesterday that there are no manufacturers of PV facilities in New Hampshire. So, when the RFP eventually goes out, we doubt very much that this, the equipment and materials, are going to be purchased within the state. It may be that the installer is based in New Hampshire, but the equipment itself is almost certainly not going to be manufactured in this state. Hence, the portion of the investment, which I estimated to be two-thirds of the total investment cost based on PSNH numbers that we were provided, it's likely to flow straight out of the state.

The third point is that, in making this investment, the assumption is that we're going to displace T&D. And, based on our calculations, we're estimating T&D investment costs totaling $126,000, which exceed the amount that would likely go to the installer, if the installer is based in New Hampshire. So, we feel that there's a high probability that there could actually be a net outflow of dollars out of the state, rather than into the state as a result of this project. So, we were not persuaded that there are any economic development benefits, hence, we did not include them. If we had concluded that there were some, because these are not direct benefits that impact electricity customers, you're not going to see a rate reduction as a result of any of these impacts. We feel it's inappropriate to include them in the TRC test. And that, at the very least, at the most, we would recommend to the Commission that they consider this

issue from a qualitative standpoint in deciding whether projects that are marginally cost-effective, let's say you've got a benefit/cost ratio of less than one, but in the 0.9 somewhere, we would encourage the Commission to take these indirect benefits into account in deciding whether to proceed with the particular project, but not to include them in the analysis as though they were going to get that. Electric ratepayers, rather than businesses in the state or select businesses, would receive these benefits.
Q. Thank you. Another criteria the Commission has to consider is the effect of the DER investment on competition in the regional power market and the state's energy service market. Did you take this issue into consideration when you did your evaluation?
A. Not in terms of the evaluation, but I certainly addressed this issue in my testimony. There's a portion of my testimony which looks -- which talks about the impact on retail competitive suppliers of Default Service -- or, not "Default Service", alternative to Default Service, retail competition. And, my concern was that, if you have a situation where, one, the utility is using what I consider to be very questionable benefits, things like economic

development and CO_2 externalities. Using those alleged benefits in order to turn what are, in effect, uneconomic projects into economic projects.

And, in addition to that, providing, in some cases, 100 percent financing to the customer, in other words, the participant has to pay nothing for the project, it's all paid for by the utility. That kind of activity encourages customers, end-use customers, to install these projects that are extremely costly, as I indicated yesterday, maybe five to six times the cost of Default Service. But they're installing -- encouraging them to install projects behind the meter, in order to economically displace Default Service. That, to me, is sending the wrong signal to those customers. It's a good thing for the customer to do it, because they're going to avoid the bill without paying anything for the investment itself. But it's encouraging competition that I think, in the provision of service to customers in a very uneconomic way, and that's going to have an impact on retail competitors who are trying to persuade customers, non-residential customers we're talking about here, to purchase power from them, rather than purchasing from the utility.

So, those two components I think have

major competitive impacts. And, in my testimony, I've recommended that, one, we don't include indirect benefits in the TRC test. And, two, any contribution by the utility to the financing of these projects should be significantly lower than the proposed 100 percent in two cases that the utility has out of three.

So, I would say that, while the focus was on its impact on retail competitors, as opposed to what the legislation refers to as an "energy service market", which I'm not sure what it -- what that means. But, clearly, we did address the competitive impacts of the Company's proposal in our filing.

Q. Mr. McCluskey, it's pretty clear that you do not support including the indirect benefits identified by the Company in the evaluation, the economic evaluation of the projects. Do you have anything more to explain -- to say explaining why you oppose including those?

A. Yes. This is a very important issue. What some states have done in order to turn projects that are really uneconomic, and I'm thinking of solar PV primarily, turn them into economic projects, is to provide significant credits, state tax credits, and that would be available to entities that installed these facilities. This is in addition to the federal tax credit, which we reflect, by the way, in our analysis. And, so, that, to me, is an upfront way of turning what is an uneconomic project for the customer into an economic project.

If the state didn't do that, but chooses, in the economic analysis, to include indirect benefits, in effect, what they are doing is the same thing as having credits, but it's behind the door, it's not in front of the door. So, you're turning what is an uneconomic project into an economic one with these so-called "indirect benefits", which are, in my mind, very questionable. The bottom line is that it has the same effect that, in the case of a state where you have credits, those have to be recovered. So, if the -- either the state is going to incur the cost, or, if they require the utility to offer those credits, the utility is going to seek recovery of those costs. Rates are going to go up.

In the case of the indirect benefits, if this had the effect of converting what is an uneconomic project into an economic one, there's going to be rate impact associated with that. Because, in effect, what you've done is, you've incurred a cost, let's say it's half a million dollars, but the benefits are only $250,000. That's going to result in rate increases to ratepayers eventually. So, why? Because you incurred the cost of, in my example, $500,000, with only 250,000 benefits. But, with the indirect benefits, you've essentially hidden the fact that there's a difference. But it's going to come back in the form of rate impacts. So, it all depends on whether you're going to have a significant expansion of these programs for this utility and for other utilities. The more projects, the larger the dollars, the greater the impact there will be on rates. And, so, when the Commission considers whether to include indirect benefits in its economic evaluations, I encourage them to take that into account, that there will be rate impacts associated with any policy decision of that nature.

Q. Thank you. The last area I wanted to explore with you is the Company's request to include lost base revenue in its cost recovery. Please explain your position on that.

A. Staff is opposed to the Company recovering lost base revenues. I think the Stratham project is a good example. Initially, they proposed to have this project located behind the meter on the Company's facilities.

So, it would have the effect of displacing Default Service power that the Company currently provides them. And, in addition to displacing the Default Service energy, it would also lose the revenues that they recover on the rates charged to those customers associated with its distribution system. That's the lost base revenue.

By locating, by appropriate redesign of the project, and hooking the system up to the utility's distribution system, they avoided incurring lost base revenues. So, I think, with appropriate consideration of the design of the project, the Company can actually avoid lost base revenues.

In addition, the legislation -- my interpretation of the legislation is that they're encouraging the utility to adopt projects that displace investments in T&D. And, so, what we're talking about is reducing the peak demands that are on the utility's distribution system. And, the best way in my mind is to focus on projects that reduce the demand, not -- rather than the energy. You can have a project that does both. The solar PV facility is going to do both. It's going to displace -- it's going to be -- presumably going to be operating on a peak day, so it's going to reduce demand. Hence, it's going to avoid investment in the T&D system. But it's also going to operate year-round. And, hence, it's also going to displace energy, which can result in lost base revenues.

If the Company were to focus in its selection of projects on projects that are essentially Load Management projects, demand reduction projects, rather than energy saving projects, then the lost base revenues are going to be much smaller. And, so, I'm not persuaded that the Company has done sufficient in terms of its design of the projects in order to warrant an order from the Commission that awards it lost base revenues on any project. Because, if you do, Commission, the Company has no incentive to design its projects that minimize lost base revenues. So, we oppose it, therefore, for those two reasons.

Q. Upon reflection, do you have anything else you'd like to add to your testimony?

A. No. I think I've said quite a lot. So, I would stop at this point.

MS. AMIDON: All right. Thank you. That concludes my direct.

CMSR. BELOW: Let me just ask, before --

I think we might want to take a break now for the court reporter. But, before we do that, let me just get a sense of how much cross-examination we might have. Ms. Hatfield?

MS. HATFIELD: Probably only 15 or 20 minutes at the most.

CMSR. BELOW: Mr. Steltzer?

MR. STELTZER: I'll have a few questions, but minimal.

CMSR. BELOW: Okay. And, Mr. Aney?

MR. ANEY: Probably similarly, about 15 to 20 minutes.

CMSR. BELOW: Okay. And, Mr. Epler?

MR. EPLER: Probably none.

CMSR. BELOW: Okay.

MS. HATFIELD: But I do have to say, Mr. Chairman, that it's going to be very difficult for the OCA to do cross on the four new exhibits. So, perhaps -- I don't know if the Company is going to be objecting to those being entered, but we will talk during the break. You know, for us to be able to come up with questions on new information might be a little bit challenging, but we'll certainly try to do that.

CMSR. BELOW: Okay. Well, let's maybe

take a fifteen minute break, till 11:15. And, we'll resume with cross at that point. We'll stand in recess.

(Whereupon a recess was taken at 11:00 a.m. and the hearing reconvened at 11:18 a.m.)

CMSR. BELOW: Okay. Is there any preference in the order for cross-examination? Mr. Mitchell, did you have any cross-examination?

MR. MITCHELL: Yes.

CMSR. BELOW: Okay. Proceed.

MR. MITCHELL: Sorry.

CROSS-EXAMINATION

BY MR. MITCHELL:

Q. Mr. McCluskey, could you go over briefly how capacity factors are determined?

A. The capacity factor, as defined in the exhibits, Exhibit number, Suzanne? What was the exhibit number?

MS. AMIDON: Sorry. I guess 11?

MR. MITCHELL: Yes.

WITNESS McCLUSKEY: Exhibit 11? Okay.

CONTINUED BY THE WITNESS:

A. The capacity factors in that exhibit --

CMSR. BELOW: Excuse me, I think Exhibit 13 is the list of solar PV projects from Fat

Spaniel.

WITNESS McCLUSKEY: That is the one I'm referring to, Exhibit 13.

CMSR. BELOW: Okay.

MS. AMIDON: Thank you, Commissioner Below.

CONTINUED BY THE WITNESS:

A. Okay. The columns headed "Capacity Factor" and "Weighted Capacity Factor" were calculated by me. And, what they represent is the ratio for each project the kilowatt-hours generated since those projects began operation, to the date that I looked at the Fat Spaniel website. So, that's referred to as the "lifetime kilowatt-hours" at some point in time. And, that is divided by the kilowatt-hours that could have been generated by that project, if it had operated at 100 percent. So, the denominator is the rated capacity times 24, which is the number of hours in the day, times the number of days that the facility has been - that particular facility has been operating since it began operation.

BY MR. MITCHELL:

Q. Thank you. And, is it fair to say that the capacity factor is impacted by the installation itself, as well as the specific equipment used?

A. Yes. There are going to be, in practice, there are going to be many factors which determine the capacity factor for a particular facility. Where it's located, whether there is shade, the actual type of PV equipment used, all of those factors, whether the owner or operator of the PV facility clears the snow from the panels or clears the dirt from the panels. There are going to be many factors. You actually see capacity factors almost zero for some facilities, so indicating they're either not operating those facilities very well or it's down for maintenance or for whatever reason. So, there's a considerable variation from one facility to another. And, hence, it's important, when you do this type of calculation, to have a reasonably large sample to produce a reasonable average. I'm not suggesting that every facility would operate at 13; some will operate above that level, some will operate below.

Q. Thank you. In the SAU project, there was -- we list a capacity factor that was greater than the average. Is it fair to say that, based on the equipment, the fact that the SAU has no obstructions in its installation, it's oriented perfectly with respect to the azimuth, and is also oriented in terms of its tilt, that we might achieve a capacity factor well above the average?

A. That is possible. I do recall in my testimony indicating that the capacity factor that was used in the evaluation for that project was high, relative to what had been indicated as the average for the Northeast. But it is perfectly possible for certain facilities to have very large capacity factors. I would question any claims where the capacity factors are significantly higher than what's been achieved in Texas and California. But it's possible that a very well-designed project could have an extremely good capacity factor.

MR. MITCHELL: Thank you. That's all I have.

CMSR. BELOW: Okay. Mr. Steltzer.

MR. STELTZER: Yes.

BY MR. STELTZER:

Q. My questions are regarding to the topic of economic development. There's been some testimony provided that there are no facilities located within the state, and that upwards of 75 percent of the cost of the panels -- well, 75 percent of the cost of the installation is going to go outside of the state. Would you believe that a solar manufacturer would choose to locate their manufacturing facility close to demand?

A. That happens in some cases. In fact, in Arizona, there are many, many such facilities installed. Partly because the state has made a concerted effort to develop the manufacturing base for PV facilities. And, obviously, those manufacturers have pushed very hard for the utility commission and the legislature to adopt policies that result in PV facilities being built in their state, so -- in order to stimulate the market for those manufacturers. But, obviously, those manufacturers will be selling in other states and in other countries.

Q. Uh-huh. And, certainly, we can say that Arizona might have a little bit more of a resource for Sun, given their climate that they are in.

A. I agree with that.

Q. And, to your point, in Massachusetts, for example, there are manufacturers of solar panels that are in Massachusetts --

A. That's correct.

Q. -- for some of the policies that Massachusetts has instituted. On the -- might it be said then that one of the reasons why a PV manufacturer might not be

located within the state is because of the relatively
low demand for solar within the state?
A. Well, I haven't done any research or much thinking as to whether the solar PV industry would be a good fit for New Hampshire. Given the climate, I would have to say, I don't think that would be the case. And, also, there would be significant competition for any manufacturer, from the likes of Arizona and California and Texas.
Q. Right. And, I recognize that there are -- or, would you agree that there are multiple variables which go into determining what the demand are within the state?
A. Certainly. Absolutely. That would be a major business decision, which would involve a host of factors, before a decision was taken to have a start-up company in New Hampshire.
Q. Okay. And, where I'm going with this is, would you believe that a project, such as the two that are being proposed, would help to increase the demand within New Hampshire to be more inviting to solar manufacturing businesses to be located within the state, allowing for more money to be withheld within the state?
A. No. I think, if the state wanted to develop that kind of manufacturing base, it would have to have

significant tax policies to do it. I just think that, in terms of just locating small facilities in the state, I would think that would be a small factor in any decision to establish a manufacturing site in New Hampshire.

MR. STELTZER: Thank you. No further questions.

CMSR. BELOW: Okay. Mr. Aney.

MR. ANEY: Thanks.

BY MR. ANEY:

Q. Mr. McCluskey, I would just like to follow up on some of Mr. Mitchell's questions in regards to determining a capacity factor. Capacity factor is a very site or project-specific calculation, isn't it?

A. That's correct, as I indicated. In simple terms, it's just the kilowatt-hours produced over what could be produced. But, in practice, what determines what is produced is quite complex, many, many factors, particularly for facilities like this. So, all of those factors, location, the angle of the panels, whether there is trees covering the panels, that kind of thing, many, many factors would go into it. The maintenance of the equipment, the equipment itself, numerous factors would determine the actual capacity

factor for a particular facility.
Q. Are you aware that competent solar installers and developers are able, in about a 30 to 60 minute period of time, accurately determine the capacity factor for a specific site location or project that somebody might be considering in regarding a solar PV project?
A. Yes. I've seen on the Web such entities selling their services or advertising to sell their services. And, it's essentially a engineering-based service that they are willing to provide. So, yes, I am.
Q. Fair enough. Now, are you also familiar with the fact that solar technology, solar PV technology has been improving, from the perspective that the efficiency of the solar panels has been increasing, so that, for any given daylight hour or for any amount of daylight, they're able to transform more daylight into actual electricity?
A. Yes. There are several universities and several research institutes that do work in this area, and they issue papers. Some of which address the particular issue that you're referring to.
Q. So, all other things held constant, as a result, the capacity factors therefore would be increasing, as the efficiency of the solar panels marginally increases

over time?
A. Yes, I think that's a fair statement.
Q. So, a historical averaging or analysis might therefore under value the likely capacity factor of a new solar PV installation? Since it is averaging the older technology, versus considering what's possible with new, more efficient technology?
A. Yes, I think that that's a reasonable statement.
Q. Would you agree that the angle or the azimuth of a solar PV installation is the most important factor in determining the capacity factor in a particular -- for a particular geographic location?
A. I'm not an engineering expert in this area, so I really couldn't comment on that.
Q. Did either PV project that's currently being considered actually provide you with the data regarding the tilt, the azimuth, whether a tracking system would be put in place, or the shading expected for the projects?
A. No, that was not part of the Company's filing.
Q. Okay. Thanks very much. In regards to the process that is being proposed by Unitil, they proposed a bifurcated or two-step process. One where public interest was determined, and then a second step where the appropriate rate recovery -- recovery rate would be

determined. Is there not also a step that precedes that, or perhaps two steps that precede that, that Unitil is employing internally? The first being is there a need to improve the distribution and transmission systems' efficiency or effectiveness or to reduce its peak or line losses first, to determine whether a DER project is something that is -- would be a value to the Company?

A. I would say, if the Company is going to claim in its economic evaluation what it calls "localized distribution cost savings", then I believe its filing -- they would, prior to making a filing, they would have to do significant evaluation of the portions of the distribution system that could potentially benefit from these projects, and also provide the results of those engineering studies in the Company's filing. If the Company is not prepared to do that type of evaluation, then I don't believe localized distribution benefits should be part of the economic evaluation. I hope I'm responding to your question.

Q. Oh, that's a fair response. But I guess I'm also trying to get at a second -- a slightly different question, perhaps let me rephrase this. Distributed -- I'm sorry. In RSA 374-G:2, under "Definitions", 1(b),

"distributed energy resources" are defined in a manner that also references "RSA 374-F:3, III", such that "distribution service companies should not be precluded from owning small scale distributed energy resources as part of a strategy for minimizing transmission and distribution costs." So, implicitly, it's suggesting that the investment in DER is intended to contribute to minimizing transmission and distribution costs. Is that a fair description, when you consider the reference of RSA 374-F:3 and regarding the definition of distribution -- "distributed energy resources"?
A. Yes. I believe that is the primary purpose of the legislation.
Q. And, so, therefore, whether implicitly or tacitly or explicitly, you would expect there to be a step in this process of determining whether transmission and distribution costs are being minimized through the investment in these DER projects?
A. I'm not sure whether I agree with that. That demonstration could be part of the Company's least cost plan filing that they are also required to make at the Commission.
Q. Was there any reference in the proposals being submitted to a least cost plan or filing to demonstrate

that that was actively being taken into consideration in this case?
A. No.
Q. There is another step that Unitil took in the process, which was the selection of the projects to actually propose. Again, I would call it a "preceding step", because it couldn't have happened afterwards, it had to have taken place before this docket or this petition was actually filed. Would you agree with that, that they have selected certain projects and evaluated certain projects for proposal to the Commission?
A. They did. That's correct.
Q. Okay. So, there is a step there, and they did not seek any type of approval or review of that essential step in this process, in regards to what DER projects merit investment or will be pursued as investments by the Company?
A. That's correct. But I don't necessarily agree that that process has to precede a DER filing. We have recommended that the Company issue request for proposals for projects. And, I anticipate, if that is -- if that recommendation is adopted by the Commission, that, as part of the process for issuing a request for proposals, we would ask the Company for its thinking in

terms of the range of possible projects that it could possibly solicit to do to achieve the same reduction or minimization of the transmission and distribution costs. So, I anticipate in the future that we will be working with the utilities as they develop RFPs, to ensure that the -- one, the right types of projects are being considered, and that all potential developers of projects are receiving a fair opportunity to compete to offer these projects.

Q. So, would you agree that the process by which they select these projects is critical, in terms of the impact this will have on the competitive energy services marketplace?

A. Yes. It could have both a benefit, beneficial, and what's the opposite to beneficial?

Q. How about "negative"?

A. Negative impact on the competitive market, depending on how it's done.

Q. So, do you believe it is appropriate, therefore, for the PUC to issue guidelines clarifying the importance of this being a neutral -- neutral process, or one that either is neither perhaps -- that it does not have -- and to ensure that it does not have a negative impact on competition in the energy services marketplace?

A. I don't think the Commission needs to issue guidelines. It just needs to address the issue in its order, and that would be an instruction to the Staff, when it works with utilities in the future on these projects, that that's an issue that the Commission considers to be important. And, the Staff will ensure, as this process develops and improves over time, that this would be one of the issues to take into account.

Q. And, in the case of these specific projects, do you believe that the process that was employed by Unitil has been done in a way that is fair to the competitive energy services marketplace, in terms of their selection of which projects and how those projects would be implemented?

A. I can't really comment on whether Unitil fairly or unfairly worked with potential developers of these projects.

Q. Why is that?

A. Because I'm not familiar with what they did.

Q. So, they did not provide you with sufficient evidence or they have not submitted in this docket clarification sufficient enough to determine whether this was a fair or unfair process for competition?

MR. EPLER: Is that a question or a

statement?

MR. ANEY: It's a question, actually. In other words, I'm asking for his evaluation as to whether he has sufficient information in this docket to determine whether the selection process was -- had a negative or beneficial or neutral impact on the competitive energy services marketplace.

BY THE WITNESS:

A. I don't believe the selection process of these first three projects was addressed by the Staff in any great detail. And, therefore, that would be an admission on the part of the Staff, rather than the Company.

BY MR. ANEY:

Q. Is that something that perhaps the Commissioners could take up in their order or instructions to Unitil in regards to this docket?

A. They could, if they were persuaded that there was a problem. I'm not sure whether the record indicates that. That would be up to the Commission.

MR. ANEY: I'd like to introduce an exhibit, and I'm not sure what number it would be.

CMSR. BELOW: Sixteen?

MS. DENO: Sixteen.

MR. ANEY: Thank you. And, what I'm

introducing are from the U.S. Treasury's website this morning, the Treasury yields on short --

(Mr. Aney distributing documents.)

CMSR. BELOW: So, we'll mark this for identification as "Exhibit 16".

(The document, as described, was herewith marked as Exhibit 16 for identification.)

BY MR. ANEY:

Q. So, I'd first like to direct you, Mr. McCluskey, to the page that has the shorter and long-term yields, I think its title is, since I don't have a copy left for myself, the "Daily Treasury Yield Curve Rates". And, could you help me by describing what you see there in regards to the effect of time on the rates that are being required by investors in federal Treasury securities.

A. This is on the second page you're referring to?

Q. It's on your second page, I believe, yes.

A. Okay. Well, it's indicating that, as the period increases, from one month up to 30 years, the short-term rate would generally increase.

Q. And, is that due to uncertainty based on your understanding of the time value of money and the

discounting of investments?
A. It's driven by risk, that is the general -- is the term that covers all of those things.
Q. And, so, this also -- these are nominal rates. So, these also include inflation, is that correct?
A. If they are nominal, then, yes, they would include inflation.
Q. And, you're very -- you're fairly familiar with financial modeling weighted average cost of capitals. Is the U.S. Treasury rate typically used as a risk-free rate in financial modeling?
A. It is. Sometimes it's referred to as the "social discount rate" as well, in projects, particularly government projects.
Q. Thank you. As we look at the other page titled "Daily Treasury Long-Term Rates", where the Treasury has identified what is an average rate for yields on securities greater than 10 years, can you read to me what it says the rates are roughly?
A. The "Long-Term Composite", "4.25 percent" at greater than 10 years, and the "Treasury 20 year", I forget what "CMT" is now, that's "4.4 percent".
Q. Based on your knowledge of financing costs, is it possible for anybody in the securities market to raise

rates without a particular tax benefit that is less
than these rates?
A. These rates are typically regarded as the minimum that
would be used in any project financing.
Q. So, is it true that any competitive energy services
provider that was seeking to raise capital in the
public -- in the private capital markets, that wasn't
able to take advantage of some tax advantage or special
government security that might reduce the rates, pay a
premium over these rates for its cost of funds?
A. Absolutely. You would be looking at much higher rates.
Q. Thank you. And, on the last page, it has -- it's
titled "Daily Treasury Real Long-Term Rates", what is
the Treasury or "risk-free" long-term rate, less
inflation, depicted here on this page?
A. You say it's headed "Daily Treasury Real Long-Term
Rates"?
Q. "Real Long-Term Rates".
A. Okay. That rate is "2.09 percent".
Q. How does that compare to the discount rates that are
being used in the financial models that have been
proposed by Unitil?
A. Well, it's -- this one is higher, the real rate is
actually higher than the rate that Unitil is using for

discounting the benefits.

Q. Okay. So, just to be clear, the risk-free rate that is used in the private capital markets is less -- is higher than the real discount factor that Unitil is using to discount the benefits. And, what effect does that have on the value, the present value of the benefits that are being calculated in these scenarios?

A. If you use a -- the lower the discount rate that you use to discount the benefits, generally, the more economic the project is going to look. Hence, by careful use of the discount rate, you can turn what are effectively uneconomic projects into economic projects. And, so, the effect is to bias the analysis in favor of a economic finding.

Q. And, based on your understanding, does Unitil have a cost of capital that is lower than the federal Treasury of the United States?

A. No.

Q. What is your understanding of the cost of capital that Unitil has?

A. Well, the current approved weighted cost of capital, adjusted for taxes, is, as I indicated earlier, 11.45 percent. The Company has updated that number, that was from the most recent rate case, which was two or three years ago, has updated that number, and it's 11.1, I believe, in its economic evaluation.

Q. What's your understanding of why the Company therefore is using a discount rate, a real discount rate, in this case of 1.66 or 1.69 percent?

A. Because it's using the rate that Synapse uses in the 2009 Synapse report to evaluate energy efficiency programs.

Q. Do you understand why Synapse has suggested that a rate below the risk-free rate, as defined by the federal government's long-term Treasury rates, why the Synapse rate is lower than the risk-free rate?

A. I'd have to go back and read the report. But I believe there's a statement in the report which indicates that that rate of 1.66 is essentially their estimate of the Treasury rate at that time.

Q. And, what time was that?

A. Early 2009 was when that report was put together, I believe.

Q. Would you -- would you accept subject to check that the long-term Treasury rate has never been below 2 percent in the last several years?

A. I've got no information to contradict that.

MR. ANEY: I would just like to note

that the same website from which I got these rates provides historic rates. I don't know if it's appropriate to reference them or not?

CMSR. BELOW: Well, no. I mean, --

MR. ANEY: It's not?

CMSR. BELOW: -- this is for cross-examination, to ask questions, not to provide testimony.

MR. ANEY: Okay. I wasn't sure whether I could reference additional data associated with those exhibits, so I apologize.

BY MR. ANEY:

Q. So, but getting back to the actual projects here, because this is really about project financing for these specific projects. You've already noted that you believe the more appropriate discount rate is approximately 11 percent for the weighted average cost of capital. Do you believe it is in any way credible to be using a discount rate less than the 2 percent current long-term federal Treasury rate for the evaluation of these projects?

A. No, I don't believe that's appropriate.

Q. Okay. Do you further believe that, by representing the benefits using that discount factor, it potentially puts Unitil, if it's able to turn around and present this project to a client, at a competitive advantage versus a competitive energy supplier, who has rates that must be higher than the federal long-term Treasury rates or the risk-free rate?

A. I couldn't comment on the statement about a "competitive advantage". I wasn't aware that Unitil was competing with private developers. I would agree that, potentially, it could take business away from private developers. Whether the intent is to compete with them, I couldn't comment on that.

Q. Thank you. Commissioner Below earlier this morning referenced certain benefits associated with lowering the peak capacity requirements of a T&D system. And that, when Unitil looks at investing in upgrading the capacity of its T&D system, it effectively has to do it for an entire year, and not just those few peak hours where things spike up. Has Unitil provided you with any estimate as to what that cost is of marginally increasing the peak capacity of either its entire system, a particular substation, or a particular circuit that might be relevant to doing an analysis as to what that alternative cost for transmission and distribution might be?

A. Unitil has, as part of Unitil's last base rate case, the Company filed a marginal cost study, which included a component that developed the marginal distribution capacity cost, and the -- no, not the transmission costs, because they don't own transmission.
Q. Sure.
A. But they provided a marginal distribution capacity cost calculation, extensive calculation, I'm not talking about one page here, extensive report, that developed the system average marginal capacity cost by voltage level, not by individual circuit.
Q. And, how do those costs compare to the value of reducing the peak costs that is provided through the distributed generation projects based on the amount of power that they're going to be able to produce?
A. Well, if you refer to Exhibit 12 in this proceeding, my economic evaluation of the Stratham project, the third item is the -- what's referred to as the "avoided distribution cost". Do you have that?
Q. Yes. And, what is the total of that?
A. Remember, this is a present value 20-year number. So, this is the sum of the avoided distribution costs for a 40-kilowatt project over 20 years. And, the total value, the total avoided distribution cost is estimated

here as $64,000, and that is calculated using the marginal capacity cost from that prior proceeding that I mentioned.

Q. So, do you believe that's a relative opportunity cost to be considering, when looking at whether these projects perhaps make economic sense from a T&D perspective?

A. That is -- that is a good guide to the distribution benefits. When you do the economic evaluation, you should not constrain yourself to looking at just the distribution benefits, even though the primary purpose of the legislation is to minimize T&D costs. If a project produces other benefits, then you should take those things into account, and that is what this calculation does. It asks the question "what are all of the benefits associated with the project?" And, you would have to include the primary one. If there were no distribution benefits, Staff would be questioning why the Company was proposing this project. So, it would have to include an element for avoided distribution cost. But it should also include all of the other benefits appropriately calculated or estimated.

Q. Thank you. When you looked at the economic development benefit that has been also assigned to the project, do you believe that the installation of a solar panel more closely resembles the construction trade input/output model multipliers or the nature of the project, I guess, reflects that construction industry sector more than any other sector in that input/output model, given what you understand about what's involved in the installation of a solar PV project and the labor versus capital components of a typical project?

A. I couldn't really comment on that. I'm not an expert in the application of multipliers and economic development. But my comments on this issue have been in a much higher level understanding what industry is or is not located in the state.

Q. So, it has been very difficult for you, therefore, to challenge or evaluate the economic benefit assumptions and projections and calculations that have been presented to you?

A. (Wells) Well, we certainly --

MS. AMIDON: Just want to -- pardon me. I just want a clarification. Are you -- is the question saying that the fact that Mr. McCluskey is not familiar with these multipliers is unable to make evaluations? Or, is it that certain information was not available to him, which impeded his analysis?

MR. ANEY: Good question. And, let me ask both.

BY MR. ANEY:

Q. Do you believe that you were able, given the information that you were provided and any modeling tools that you were provided, to adequately assess whether the economic benefit or development benefit that was suggested is appropriate?

A. You said was I "able".

Q. Yes.

A. I would say that the department in which I work does have resources. We have people very familiar with those calculations.

Q. Then, maybe I should rephrase it as "the PUC in total".

A. If I could finish?

Q. Yes. Sure.

A. We do have people familiar with those calculations that could have -- I could have requested assistance, if we had chosen to evaluate, say, the detail, the nitty-gritty of the calculations that were performed. We chose not to do that, because we felt that we could critique the evaluation at a higher level, and hence there was no need to get into the gory detail of multipliers.

MR. ANEY: Okay. Thank you. Those are all the questions I have. Thank you very much.

CMSR. BELOW: Okay. Thank you. Mr. Epler, do you --

MR. EPLER: Yes. I just wanted to inform the Commission I actually will have some questions.

CMSR. BELOW: Okay. Fine.

MR. EPLER: But probably not more than five or ten minutes.

CMSR. BELOW: Okay. Thank you. Ms. Hatfield.

MS. HATFIELD: Thank you. Good afternoon now, I think it is, Mr. McCluskey.

WITNESS McCLUSKEY: Good afternoon.

BY MS. HATFIELD:

Q. I believe in your testimony, both in Exhibit 8 and today, you testified that you "oppose including a value for any potential economic benefits in the analysis of these projects", is that correct?

A. I believe I said that "we were not persuaded that there was any economic development benefit. And that, if there were, we think it's appropriate for the Commission to take that into account at a qualitative, rather than quantitative, level."

Q. What do you mean by "qualitative" and what's your suggestion to the Commission about how they should "qualitatively" take those effects into account?

A. Well, I think, first of all, I would hope that the Commission would do the same kind of analysis that Staff did. Look to determine whether there was a likelihood that the investment that's being identified would actually remain in the state. And, if they were persuaded that a portion of it would remain in the state, they could then use the evidence about multipliers in the record and make some determination as to what economic development was likely to happen. The next step would be to decide "is it appropriate for the Commission to then consider that a portion of that economic development or all of it to be a major factor in a decision that would approve or disapprove a project?" Recognizing that we're talking about indirect benefits, not benefits that the electricity consumer is actually going to realize firsthand, as it were. So, I would hope the Commission would go through that kind of evaluation in determining what to do with economic development, if they believed there was some to be had.

Q. Do you recall in your testimony, on Page 19, you were discussing your alternative proposal to the DERIC charge that Unitil proposed?
A. I don't have it in front of me, but, yes, I proposed the step adjustment mechanism.
Q. And, in your description in your testimony, you give other examples, if I recall correctly, including the Bare Steel-Cast Iron Replacement Program in the natural gas and water investments by water utilities, is that correct?
A. That's correct.
Q. And, do you recall yesterday I asked Mr. Gantz if he was familiar with a recent order in a water case, where the Commission approved a Water Infrastructure and Conservation Adjustment mechanism?
A. Yes, I recall that conversation.
Q. Would you consider that mechanism to be something akin to what Staff is proposing in this case?
A. It's the same type of concept. It's a different -- I did take the opportunity yesterday to talk to one of -- the Director of the Water Division, who explained in a little bit more detail than what's in the order as to how it works. The rate mechanism is a little bit different from what I had in mind. But I think the

concept is the same. It applies to non-revenue-producing assets, which is what we're talking about here.

The one thing that was not mentioned, based on the conversation that I mentioned, it does not include the recovery of expenses. And, we are definitely recommending that the expenses, as well as the investment, be recovered through the step adjustment surcharge that we've proposed.

Q. Would you say that one similarity is the sort of two-step approach that you are proposing?

A. The two-step? What are the two steps you're referring to?

Q. Meaning that the Company first comes in and describes the project that they're planning, and then later comes back in to include them in rates to recover costs, only once they're in service.

A. Yes. I would call that the "process", and we're certainly supportive of that process. What we are addressing here is, once they come in in that second step, what mechanism are we going to use to convert the costs that they claim they have incurred into a rate? And, we think there's different ways it can be done. You can have a surcharge, where it's obvious on the bill how much is being collected for these particular investments. You could roll the costs into the base rates. That would require the base rate to be changed every time the Company came in. The first approach would leave the base rate that came out of the recent rate case in place, and you would just change the surcharge from year to year, as the investments change and also the expenses change.

Q. I have a few questions of clarification on some of your new exhibits today, specifically starting with Exhibit 12.

A. Yes.

Q. And, this I believe is your updated analysis of the Stratham proposal, is that correct?

A. That's correct.

Q. There's a column to the right there. Do you see two columns of numbers?

A. Yes, I do.

Q. What does the column to the right represent?

A. Well, there are several pieces of information there. The first -- the first, let's look at the percentage "55.8 percent". That's comparing the total benefits to the total costs. So, it's indicating that the benefits, they're only recovering the direct benefits, they're only recovering, say, 56 percent of the total costs in this analysis. And, there are some other percentages which indicate how that 55.8 is broken down, okay?

Then, we have the number "$0.57". And, what that does, it tells you, based on these costs, these lifetime costs, present valued, divided by the projected lifetime kilowatt-hours generated, it tells you what it's going to cost. That's 57 cents per kilowatt-hour. That I would consider to be hugely expensive for energy, which can be bought in the competitive market at eight to nine cents.

Q. And, at the bottom of your table, you show values for "Economic Development", "CO2 Externality", and "Localized Distribution", is that correct?

A. Yes.

Q. And, you've also monetized those amounts in the right-hand column?

A. That's correct.

Q. But you have not included those in your benefit/cost ratio?

A. I have not. That's correct. The intent of calculating those numbers was, in terms of economic development, for example, above I've indicated that, in order to have it break even, you're going to have to have benefits that come out equal to 57 cents a kilowatt-hour in total. And, this economic development benefit, which comes from the Company, is itself worth 45 cents. So, it's indicating that you can have projects, which are grossly uneconomic, and can be found to be economic, if you include an economic development benefit of 45 cents. So, it's just indicating the importance of this economic development component. It can essentially wipe away any result that came from a Total Resource Cost Test using direct benefits. So, this economic development benefit is critical as to whether that's included or not in the Commission's decision. And, another way to look at it, the 45 cents, if that were ever used to decide whether to approve a project, ever used in full, it's essentially saying that ratepayers will have to pay 45 cents, general ratepayers will have to have their rates increased by an amount of 45 per kilowatt-hour generated by this project as a subsidy. So, it would result in significant rate impacts if these projects were ever done on a large scale.

Q. Looking at the Company's similar analysis, which is Exhibit 5, --

A. Bear with me a moment so I can get that. Okay. Yes.
Go ahead.
Q. Is it fair to say that the company has, at the bottom of that table, presented the possibility that the Commission could weight economic development benefits at something less than 100 percent?
A. Based on Mr. Gantz's testimony yesterday, they have indicated that that's a possibility. If they truly believe in the analysis that resulted in the economic development benefits, and you believe that it's appropriate to consider those benefits in the analysis, I don't understand why you are proposing to take into account only 25 percent.
Q. Looking just quickly at your Exhibit 14, do you have that before you?
A. Which one is that one?
Q. That is the REC benefit analysis that you performed.
A. Of the Company's $133,000?
Q. Yes, I believe so.
A. Yes. Okay, I've got that one.
Q. Okay. The title at the top of the document says "UES Analysis". Is there any analysis that you performed that's in this document?
A. Sorry. It does say "UES Analysis". It's "my analysis

of the Company's calculation", is a better description of it. I was trying to reproduce the $133,000.

Q. So, you have used their data and you've tried to analyze their projection of the REC benefits?

A. Not so much their data. The ACP, the current one, is a fact. The escalation rate I believe came from a document of the Company. The next column, the 75 percent figure is the Company's assumption. The 52 megawatt-hours is the Company's number. And, everything falls out. And, the PV factors are the Company's numbers as well, based on 3.25 percent.

Q. And, the "PV factor" is the -- I think you testified earlier is "present value", it's not "photovoltaic"?

A. That is correct.

MS. HATFIELD: Okay. I have no further questions. Thank you.

CMSR. BELOW: Thank you. Mr. Epler.

MR. EPLER: Thank you. Mr. McCluskey, it's always a pleasure.

WITNESS McCLUSKEY: Likewise.

BY MR. EPLER:

Q. Recognizing that you're not a lawyer, I would like you to turn to a copy, if you have one, of Chapter 374-G.

(Atty. Amidon handing book to the

Witness.)

WITNESS McCLUSKEY: Okay.

BY MR. EPLER:

Q. Now, is it your testimony -- well, first of all, can I get a clarification? The position that you're putting forward here, is this the position of George McCluskey or is this the position of Staff? In other words, is this reflective of the Staff's position on these issues in this docket?

A. Well, recognizing that we have a new department which has an interest in these kind of issues, when I developed my direct testimony, I specifically stated that it was "testimony on behalf of the Electric Division."

Q. Okay. Thank you.

A. And, it's been reviewed by the head of that division.

Q. Okay. Now, is it correct that the -- that Unitil is not under any obligation to come forward and make the kinds of proposals it has made in this docket?

A. That's correct. I read the legislation to be that utilities can volunteer to develop or invest in these projects. They're not mandated to do it.

Q. And, there's no penalty if we did not make these proposals, is that correct?

A. That's correct.
Q. Now, is it your testimony that the Commission should only approve projects that are economic? And, when I say "projects", I mean projects that are put forward pursuant to this statutory provision.
A. I believe I've indicated to the Company, in response to discovery, that Staff, at least this Staff person, would recommend approval of projects that had a benefit/cost ratio below one, provided they were not too far below one. I think I used the term "marginal". So, I would certainly -- I could certainly anticipate recommending approval of projects that had benefit/cost ratios in the 0.9 range. As to whether I would recommend projects significantly below that, I couldn't say until I come across one. And, in fact, we have come across one, at least based on my evaluation, and I've concluded that it's not in the public interest, and hence we have not recommended approval of it.
Q. And, you concluded it's not in the public interest, because, at least in terms of the most current evaluation as shown on Exhibit 12, it has a benefit/cost ratio of 0.56?
A. That's correct.
Q. And, you arrived at that calculation based on your

analysis of the factors in 374-G:5, II?

A. Almost all of those factors. I know there's one called "energy security", which we -- which I personally found very difficult to monetize. So, we -- I did not mention that earlier today. But the other factors, "environmental", "reliability", "economic development", I have testified to today, and I believe my analysis takes those criteria into account.

Q. Okay. Now, could I draw your attention to the paragraph in RSA 374-G:5, II, the last sentence before the listing of the factors. It's the sentence that begins "Determination of the public interest".

A. Yes.

Q. Okay. And, do you see that that sentence says that, well, I'll read that sentence: "Determination of the public interest under this section shall include but not be limited to consideration and balancing of the following factors:" Is that a correct reading?

A. That is correct.

Q. Would you, and again, recognizing that you're not an attorney, would you agree then that you can consider and balance factors (a) through (i) and still -- but that's not the total sum of the factors to be considered by the Commission?

A. That is certainly an obvious interpretation of that language.
Q. So, in other words, the Commission can see your -- take your analysis into account, which, by your testimony, believe it's uneconomic, but it is not restricted to considering just the type of analysis that you've done?
A. Absolutely. I'm not -- I'm not sure at this moment what other factors would be appropriate to consider. But, with time, I'm sure I can come up with some other issues. But, as I said, my recommendation is based on what you see on that exhibit.
Q. But that's not the sum total of factors to be considered in determining the public interest, under this statute?
A. That is, as I indicated, a reasonable reading of this, of the language that you read out.
Q. And, moreover, there's an additional section, IV, which states that "The Commission may add an incentive to the return on equity component as it deems appropriate to encourage investments in distributed energy resources." Did I read that correctly?
A. You did.
Q. And, so, it's possible that the Commission could actually take the analysis that you've given, showing

no economic benefit, according to the analysis that you've done, but still determine that a project is in the public interest, and give the Company an additional incentive return, and still be within the statute, is that correct?

A. It could, as I've said. We're only advisers. The Commission will make its own determination. It could view the statute more broadly than is reflected in our analysis and make a decision accordingly.

Q. And, Unitil has not requested an incentive return for these projects, is that correct?

A. Not for these projects, that's correct.

Q. Now, there was a previous colloquy you had with Mr. Aney, with regard to 374-G:F, II [374-G:5, II?], and I believe you were talking about under that Subsection (i), the "effect on competition"?

A. Yes.

Q. Is there a requirement that a project be fair to other competitors in the statute?

A. No. It's that the Commission just take it into consideration.

Q. So, that's a -- that would be then just a factor to balance? In other words, it's possible that a project could have a negative effect on competition?

A. It's possible that the Commission could be persuaded that it had a negative effect and applies very little weight to that factor.
Q. And, do you believe that there has been a showing that the two projects proposed by the Company have a negative effect on competition?
A. With regard to the Stratham project, which has been redesigned, now it's a utility project. If a decision is used -- is taken to use the indirect benefits to result in a determination of the public interest, and potentially it could impact competition, not so much for -- in the provision of retail energy service, because now it's behind the -- it's in front of the meter, but it's possible that some private developer -- let's me take that back. Because what the -- the utility is actually going to go and issue an RFP to acquire this project from the market. Potentially, Mr. Aney and others can bid to provide that PV facility, if they choose. So, in that case, I'm not seeing a negative impact on the provision of distributed energy resources.
Q. And, would you characterize the marketplace for distributed energy resources as a "mature market" in New Hampshire?

A. Mature? I, really, I can't comment on that. I don't know enough about that market. I would expect that it's a developing market, rather than a mature market.
Q. Now, there was reference, and I apologize, I don't recall exactly when it was, but there was reference to the "Definition" section, 374-G:2, if you could turn to that, and the definition of "distributed energy resources". Do you have that section in front of you?
A. I do, yes.
Q. And, now, that's -- this particular section of the statute is the "Definitions" section, is that correct?
A. That's what it says.
Q. So, in other words, you could take this definition and place it within the "Purpose" section in order to have -- if you weren't sure of the term "distributed energy resources" within the "Purpose" section, you could take the definition and insert it in there to give you a better understanding of the "Purpose" section?
A. I would think that's how most people would approach it.

MR. EPLER: You know, I think I'll save my next point for my written statement, rather than to try to walk Mr. McCluskey through that. Thank you.

Also, I just wanted to note, I didn't want the record to close without the Company pointing out that we appreciated the work and the effort of Staff in this process. It really was an iterative process. And, we did gain significant benefit in having their input. And, so, I just -- that's not -- it's not always the case. We are often at odds. But this was a particularly beneficial one, and so I just wanted to compliment Staff on that.

WITNESS McCLUSKEY: Thank you for that.

CMSR. IGNATIUS: Thank you. Mr. McCluskey, I have a couple of questions.

BY CMSR. IGNATIUS:

Q. The statute envisions non-traditional approaches to bringing down distribution costs, looking at new ways of encouraging demand reduction. Isn't that correct?

A. That is the broad purpose, I think, of the legislation.

Q. And, it envisions, in some cases, partnerships between the utility and customers in deploying some of these new investments?

A. It certainly includes that structure as one option to consider.

Q. Do you place any value on those sorts of non-traditional approaches?

A. I think it's always good for the utility to work with its customers, particularly when there is benefit to the customer from that work. And, certainly locating one of these projects behind the meter has the potential to benefit the customer significantly. My concern is, if that is done at the expense of all other customers, when the benefits do not approach the costs of that particular action. And, so, I just want to make it clear that Staff is behind DER 100 percent, but we are not behind uneconomic DER.

So, for those customers who are fortunate enough to be involved in one of these projects, I think the customer has to put something on the table. And, the general body of ratepayers has to get something back on a net basis, or at least break even. I think it's wrong to have -- to have certain fortunate customers who benefit greatly, at the expense of every other customer, who really doesn't have a voice in this process. So, I think our job, the Staff's job, is to advise the Commission when we think that balance is out of whack. And, I think that's what the "public interest" language of the statute is getting to.

Q. Although, you would concede that the "public interest" is defined not specifically -- not so narrowly as a pure economic cost/benefit analysis?

A. I think this is one of the really good things about the legislation, that it doesn't tie down the Commission, the utilities, and the Commission Staff, as to what is a good project. It lays out certain criteria. And, it's for the Commission to determine what is in the public interest. But, you know, this is, while it might be new legislation, the ideas are not new for this Commission. We've had other projects, energy efficiency projects, for example. And, there's been, over time, a methodology developed on how to evaluate those projects. And, I suspect we should take what we learn from those projects and apply them to these, and not necessarily do something completely new. So, Staff's approach to this is really taking what's happened elsewhere, and common sense, and said "if this is what we do to evaluate projects, similar projects elsewhere, then why would we do something different in this particular case?" So, we've taken -- in fact, the utility actually did this. It used a model from energy efficiency as the basis of its evaluation, and Staff has basically come along and tweaked it in certain places. So, it's a new legislation, new projects, but I think the analysis that you apply to them is not new.

Q. There's been discussion yesterday, and to a lesser

degree today, about the potential for the investment dollars for the Stratham project going out-of-state, and not retaining a significant portion of that investment in-state, because the vendor of the components doesn't even exist in this state, correct?
A. I would say there's a high likelihood that a significant portion would flow out of the state.
Q. Keeping that thought in mind, I want to shift gears to your Exhibit 13, which is the list of solar PV in New England. And, you said that this isn't necessarily an exhaustive list, but it was a pretty good list of what you gleaned from the Fat Spaniel database, correct?
A. It's -- I would think it's probably not too big of a percentage of the total. There's many, many more projects out there that's not reflected here. But I think this list is big enough to support the analysis that we undertook.
Q. All right. I found it striking that, of this list, and I didn't count up how many, but there's only one facility in New Hampshire of any size, and that's the PSNH installation that was just recently put on line?
A. Yes. That's correct.
Q. So that, for solar PV RECs, there are currently very few New Hampshire based providers that would qualify

for -- that qualify for the New Hampshire Class II RECs who are actually based in New Hampshire?

A. I think that's the case.

Q. The more we would develop some solar PV in the state that would qualify for Class II, we would then allow more dollars to stay in the state that might be going out-of-state, correct, in the sense of payment of RECs?

A. If the facilities that provided the RECs were located in New Hampshire, then they would definitely retain some of the dollars that are spent in this area today by the New Hampshire utilities, that's correct.

Q. So, it may not be a one-for-one match, but it's something of a flip of the concern about the components, the vendors who are selling the components of building a solar PV array being out-of-state, you would lose some of those investment dollars. By creating more solar that qualifies for Class II under New Hampshire, you would be retaining some dollars that otherwise would be going out-of-state, isn't that correct?

A. It -- They would, and we've recognized -- yes, I think your point is an economic development point. You're saying that there would be New Hampshire businesses, developers of PV facilities, that would receive those

New Hampshire dollars, rather than, say, a Massachusetts developer, that is correct. And, that is certainly not taken into account in my analysis or comments. To be honest, I haven't thought about it. And, I think I've been doing this long enough to caution about accepting something without thinking about it for a while. There could be many twists and turns with this. But it appears from what you've said that, yes, that is one way that this development of these projects might benefit New Hampshire.

Q. Can you envision a solar project that would qualify under the kind of economic analysis that you've done on these two projects?

A. Not at this moment. And, this is -- I just want to make it clear that this is just not George McCluskey-Analyst talking. There are many eminent economists that have looked at solar PV nationwide, not just in New England. Bernstein, in California, a very highly-regarded economist, supporter of environmental and renewable issues, studied solar PV in depth recently and issued a report in 2009, which basically concluded that they are significantly far away from being economic, solar PV facilities, without taking into account subsidies from federal and state government. Based on the actual costs and production of the facilities, he's concluded that there needs to be a rethinking of this particular resource, because it just can't compete with central station provided electricity today. And, even though the Chinese since then have certainly pushed down the capital costs of these facilities, it's going to require a significant reduction in capital costs to make the analysis closer than it currently is. And, so, I would say that my analysis seems be supporting what he concluded in a much more in-depth study. And, if it's useful, I could provide a copy of that for the record.

So, at the moment -- the Company responded to my initial testimony with regard to the behind-the-meter project, responded appropriately, and I was initially hopeful that some of the problems in the economics of these projects would be eliminated with the redesign. But it's turned out that, even with the federal tax credits, which significantly lower the cost of these facilities, that there is still a major shortfall when you just consider the direct benefits. And, so, I'm not too hopeful that these things are going to be able to stand on their own.

Unlike the solar hot water system for

Crutchfield, where, based on a first snapshot, it was clearly cost-effective. And, so, we -- it's a great shame that that project is not going ahead, because that one can really stand on its own. So, to me, in terms of where I'd like to see the state go, that's an area where I think the state should be looking at, developing solar hot water systems, not systems that require the Sun's energy to be converted into electricity. Because, at least in this part of the country, the output of those facilities is not that great, compared with the capital cost, and that's coming through in these numbers.

Q. The statute, in the "Purpose" section, Section 1, says that it's in the public interest to "encourage New Hampshire utilities to invest in distributed energy resources [that are] clean and renewable and benefit the system." What would you consider appropriate encouragement of those investments?

A. First of all, full recovery, quick recovery, consistent with the recovery method specified in the legislation. In terms of the components that can be recovered, lost revenues is not explicitly mentioned, but there is this language which talks about a "premium" on the return. I'm sure I'm going to get fired by my director in suggesting that you could consider recovering lost revenues through a premium, but that's one possibility. If you consider that, it might be appropriate to do it for projects that (a) are cost-effective, reward the utility for coming forward with projects that benefit everyone, not just the participant that was selected. They're already getting their return on the investment, but that could be viewed as, well, that's just replacement for the lost return on the T&D. But we talk about a higher principal, these are highly capital-intensive projects, so you would get a return on that. That's the only thoughts I've got at the moment on it. But quick turnaround for projects.

One of the reasons we've put a lot of effort into the methodology, we want to have this process like Default Service. Where you come in quickly, get it reviewed, get it out. And, we'd like to have that, the process developed, where there's very little dispute as to what's going to be evaluated, how it's going to be evaluated, and what the Staff -- what restrictions are within Staff, in terms of what they can propose, what they can't propose.

So, I think, for the utility's bottom line, it's always cost recovery and a return, and the

level of the return is, obviously, important.
Q. You had also said you might imagine a project that didn't meet a cost/benefit test of one, but was close to it, might be appropriate, if other factors were present in the balancing of whether it's in the public interest?
A. Yes. Yes. You know, these are long-lived projects, and we're using estimates. And, so, there has to be some uncertainty about the numbers. We do our best to have the numbers be as realistic as possible. Because there's some uncertainty about the outcome, I don't think it's appropriate to have a bright line test of benefit/cost ratio of one or more than one. If it's below one, then it's not unreasonable, particularly given the nature of these projects, this is an important new area that the state is trying to develop, and so you might consider approving projects that are not -- don't quite meet the standard for that reason, because you want to develop this area, but I think there has to be a limit. And, if it gets too far below one, the costs to the consumers are too great. I don't think the consumers would expect us to be approving projects which have a benefit/cost ratio of 0.5.
Q. One number clarification. You had testified that you

thought a discount rate of 1.66 was not appropriate and too low. In one of Mr. Aney's questions, he -- one of the assumptions in his question was that you believed the appropriate discount rate should be "11 percent". Is that your position?

A. I believe the Company, that these -- these are utility projects, that's an alternative to doing traditional T&D. Typically, the utility, whenever there's a filing at the Commission, typically uses its overall cost of capital as a discount rate. Some utilities use 10 percent, because it's a standard to use 10 percent, rather than to determine what the actual cost of capital is. So, they may use, in evaluations, a standard 10 percent. I think that is intended to be a proxy for the overall cost of capital. And, since this is an alternative to that, it's not clear to me why we're not using that factor to discount the costs and benefits in these projects. So, I would recommend either the standard 10 percent or the overall cost of capital.

CMSR. IGNATIUS: Thank you. Your testimony has been very provocative, but also very helpful, and I appreciate it.

WITNESS McCLUSKEY: Thank you.

CMSR. BELOW: I have a few questions. I'll try to get through them quickly.

BY CMSR. BELOW:

Q. Starting with looking at Exhibits 14 and 15, I'm a little confused --

A. Commissioner, which ones are those?

Q. Exhibit 14 is your analysis of UES's analysis of the 20-year REC benefit --

A. Okay.

Q. -- for the Stratham solar PV facility. And, Exhibit 15 was the excerpt from the AESC 2009 Study, --

A. Okay.

Q. -- with regard to REC prices. And, in Exhibit 14, and maybe this kind of dates back to when the project was proposed to be behind the meter, but you've got a reference to "Load Reduction 52.00", referring to 52 megawatt-hours, which is the projected annual -- average annual output of the proposed project, correct?

A. That's correct.

Q. And, the suggestion that load reduction or demand reduction, and the reference to REC costs, suggest that this might be a cost that was avoided by reducing the load for which UES needs to procure RECs. Is that what that suggests?

A. There's actually two benefits, REC benefits. The utility, if it reduces its retail load, it avoids having to procure REC allowances. A second benefit is that, if it has a renewable project, it can go and receive payments from the, whatever it's called, their "RPS fund". And, that's what this is supposed to be calculating. So, if I've described it as a "REC cost", then, correct, that's the inappropriate labeling of that.
Q. So, what this exhibit really shows is the value of the RECs that the solar PV would produce, using their assumption that the value would be 75 percent of the AC price for solar RECs?
A. That's correct.
Q. Okay. So, it's really a REC income stream that the Company's projecting here?
A. Correct. I put this together pretty quickly.
Q. Okay.
A. And, so, yes, I used the wrong labels to describe it.
Q. And, so, could you describe -- well, just to switch to Exhibit 15, Exhibit 15 shows the first potential value you were referencing, which is, in looking at avoided energy supply cost, and, of course, this is in the context of looking at how to value energy efficiency

benefits of the overall study, says, you know, "if you can reduce load for -- by a megawatt-hour, you will avoid RPS compliance costs", which is a small percentage, particularly with solar RECs, it's a very small percentage of the total megawatt-hours. And, this is a table that shows the sort of assumption that's embedded in the overall avoided energy cost, how much of that is attributable under their set of assumptions for a particular group of RPS compliance costs, and it's by state. So, it has a cost for a megawatt-hour of reduced load how much might be saved in avoided compliance costs. Is that a fair characterization of what you understand this to be?
A. That's correct.
Q. Okay.
A. You're right. This particular exhibit is dealing with the first benefit that I described, the avoided REC cost that the utility would otherwise incur. My only point in using this is that, in order to come up with that cost, they had to project the value of RECs for Class II. And, all I'm saying is that their expectation of that value is considerably different from what's reflected in Exhibit 14.
Q. So, in Exhibit 12, though, I think you had expressed a

concern that I presume, and you can clarify, that is embedded in Exhibit 12, which is perhaps a couple concerns. One is that they were -- the Company was double-counting REC value, in terms of both showing the benefit of the Class II RECs that it would produce, perhaps overestimating that value in and of itself, but you also expressed a concern that the benefit of avoided energy had some avoided compliance costs, which might not actually exist with the Stratham reconfigured project. How did you -- what I want to understand is, how you have reflected these two different concerns in your own take, analysis on the benefits?

A. Within the avoided energy costs, I estimated, using the REC values in Exhibit 15, is that correct? I don't have it written on here.

Q. Yes.

A. Using the values reflected in Exhibit 15, I determined that the present value over 20 years is worth $20,000. So, I needed to back out that $20,000. And, initially, my REC value was $52,000, and I took 20,000 away, which left 32,823.

Q. Okay. So, you've netted out the, essentially, REC -- RPS compliance cost that's embedded in the energy benefit cost, --

A. That's correct.
Q. -- and subtracted it out in the "REC value" line, sort of netting -- subtraction of the first benefit that doesn't exist now, because it's in front of the meter, from the benefit from selling -- producing the RECs?
A. That's correct. And, I did not touch my method of calculating the $52,000 that I had initially, which I consider now to be overstated, based on the Synapse numbers. I just left that. And, so, I'm saying that both my initial number, the 52, and the Company's 133,000, are inflated, based on the Synapse numbers. But I didn't make that adjustment in my calculation.
Q. Okay. Thank you. Looking at Exhibit 13, do you know the date that the "Lifetime Electricity Generated", what date that is through to? This is the spreadsheet you created from the publicly available data from Fat Spaniel Technologies.
A. Yes.
Q. Which I believe is a monitor that reports production for purposes of qualifying for RECs.
A. Yes. When I did this calculation, I had to calculate the number of days the facility had been operating. I remember that, in 2010, I had 49 days. So, what day is 49 days? So, it's February what?

Q. 18th or so.
A. February 18th I did the analysis.
Q. Okay. Which is why, if a facility didn't have an estimated in-service date, you couldn't generate a capacity factor, even though you had design capacity and electricity generated, you also needed to know the number of days it had been producing?
A. That's correct.
Q. Okay. But you didn't try to adjust for when things were placed in service, relative to when they ended up producing. So, for instance, if you look at the PSNH project, which I think is the last one in the "KW Management" company names, it shows it went into service on "06/01/09" --
A. Uh-huh.
Q. -- and produced through, say, February 18th a certain amount of electricity, which represents more of the year that's below average, i.e. the fall and the winter, than the part of the year that's above average, which is the spring and summer, in terms of solar insulation?
A. That's correct. I fully expect the PSNH capacity factor to rise. But, given that, what have we got left? We've got the spring and summer, one would

expect that those capacity factors, that's going to push up the capacity factor. But it's starting at a fairly low level, 9.16. I'm fairly confident that it's not -- you know the English like to bet, if you'd like to have a wager on the outcome at the end of the first year, I would be astonished if it's significantly above 13 percent, given where it is today.

Q. And, likewise, looking further down on the list, the "PECI", the last one on that list, is a particularly large project, 391.69 kW, went into service on, according to this, September 4th, 2009, so it produces a fairly significant weight, but shows a low capacity factor. Is that -- would you -- is it fair to say that that's likely to rise over time, since most of their production has been in the half of the year that is below average insulation?

A. That's correct. That kind of, with it being a large one, that could potentially push up the percentage, which might explain why I didn't use 13 percent, and I used 13.5. So, I've got a little bit of leeway here for factors like that.

Q. But, actually, you don't know, and it's not disclosed in the information about what the shading percentages of these are or anything about the orientation or things like that. So, we just don't know. This is just a sample.

A. I would expect that we've got all types of designs, different types of manufacturer, different shading, different angles for them. And, I think that's why it's important to have a fairly large sample that gives you a comfortable -- gives you some confidence that the number is not impacted too greatly by a specific facility.

And, also, I would just throw in, Commissioner, that, remember, I did use the number from NREL, which apparently used all PV facilities in the country. Every PV facility in the country was in the NREL database. And, so, the 13.5 that I do use is the Northeast average. So, that is my preferred one to use. I'm only using this exhibit as support for using the NREL number, that seems to be in the same range.

Q. Okay. I think there were some discussion about how transmission and distribution was valued at UES's marginal cost, based on the recent study in their rate case. Is it fair to characterize that as sort of just a system average that looks at for a given kWh or megawatt-hour -- actually, I should say "megawatt" or "kW" increase in demand, that that reflects sort of the average value of avoiding that or the average cost to accommodate that load growth?

A. It clearly is an average. As I indicated, they calculated marginal costs for different voltage levels, and we had to turn that into an average for ratemaking purposes. And, so, this number reflects the average, adjusted for losses, and adjusted for overheads and O&M. So, this is a fully loaded avoided cost. And, to give you an indication of how large it is, the -- in using the average cost that I average, marginal cost that I recommended, I think we increased probably four times the avoided cost that the Company had in its initial filing. So, we didn't propose that to reduce it. We -- I think we were, if my memory serves, four or five times higher. So, if you looked at the summary sheets for Stratham from the initial filing, you'll see that the transmission and distribution numbers are significantly higher in dollars than what the Company provided. So, you know, I don't want you to think that we've tried to minimize this. We have actually thrown the kitchen sink at this project, and it still falls short.

Q. And, in looking at that number, did you have an opportunity to look at the Synapse AESC Study, and do you know if it suggests that, if there are specific -- company-specific numbers for avoided distribution costs, that those be substituted for the default numbers in the AESC Study?

A. I read the report several times. And, I know they say that with regard to externalities. They say it's up to -- we make these calculations, but it's up to the state commission to determine whether they want to do that. I don't recall similar language when -- in the section talking about T&D, although I could have missed that. But, you know, they actually came out with a region-wide T&D cost, which we were initially going to use, until I compared it with the number from the last rate case, and we decided to use Unitil's avoided cost.

Q. And, do you know if Unitil's avoided marginal cost is based on simply an average kilowatt of load growth versus a kilowatt of load growth at peak?

A. It's at peak. The marginal cost study is an index study done by a consultant for the Company. And, I was the analyst that reviewed that. And, it's a terrific study. They go in detail, they don't do every circuit, but they look at every voltage level. And, they've got different losses for different voltage levels. And, all of the data that they use to create these numbers, a lot of study goes behind them. You can question some of the numbers, but, you know, they made a great effort to come up with realistic avoided costs. And, so, that's why I recommended using the avoided cost, because I've got some confidence that they are realistic numbers.

Now, do they really reflect the cost that it avoided in the locality that these facilities are constructed? I don't know the answer to that, because the Company has never done a detailed study to really identify what those local benefits are. They may be greater or less than what the ones that we've got. Until the Company does that study, we would be opposed to them using anything other than the avoided costs.

Q. Along those lines, would it be your opinion that a strategy to avoid or minimize transmission and distribution system costs might, over time, as it becomes more refined, look at specific circuits, specific substations, identify those that are approaching capacity, that don't necessarily have upgrades planned, but might need one in the foreseeable future, and evaluate whether particular projects could help either completely avoid or defer further into the future those system upgrades by being located in proximity to those circuits or substations in a way that would actually help avoid specific potential, foreseeable upgrade costs?

A. I think it's always good to do more analysis. The question is, "how much effort and time do we want to spend on this?" We're talking about economic evaluations. And, is the result going to change significantly, compared with the result that you get from what I think is a reasonable first shot at this evaluation. I question whether it's worth that effort. But it's always good to refine your analysis, provided you don't have to spend more money than you actually get out of the project to do it.

Q. Okay. When you were discussing the "economic development" question, of how -- whether it was reasonable to try to quantify that, you made some observations that you had estimated that maybe two-thirds of the cost of a solar PV type system was primarily for equipment, maybe one-third was for labor or other costs that might be locally incurred. And, then, you compared to that to if a traditional T&D investment was made. Do you have a sense or do you -- did you look at the question of how much, when a T&D

investment is made, such as a substation upgrade or a line capacity upgrade, how much of that is for equipment and materials that might be purchased and manufactured from out-of-state, versus local labor to design and install it?
A. I didn't do that analysis. I just compared what was left of this investment, one-third, which is $90,000, compared it with the avoided costs that we're showing here. I think you're suggesting that what we need to compare it with is the investment component of that avoided cost, not the total avoided cost. Is that what you're saying?
Q. Well, I'm just aware that, generally, investment in electric system capacity is characterized as both "capital-intensive" and "equipment-intensive", as opposed to "labor-intensive". Although, ice storm and wind damage you might say is much more labor than equipment. But I'm just trying to get a sense of how the two might compare and if you had knowledge of that. But, if --
A. Well, we can find the answer to that. Because, as I indicated, in developing the avoided cost, we start with the capital costs, and we add the return on it from the marginal study, and then we have to adjust it

for overheads, which are essentially the labor costs that the utility is going to incur in order to invest in distribution. And, so, I know what those adders are. And, so, we can make an estimate as to what portion of the avoided distribution cost is labor.

Q. Okay. I think my final question concerns Exhibit 10, which we've requested the Company to provide. That's the updated rate impact, as well as the -- sort of the revenue requirement and cost/benefit analysis for both of the two projects on a common basis, and then looking at the two combined.

A. Yes.

CMSR. BELOW: And, I want to ask Mr. Epler, if, in providing that, that can also be provided in a working Excel file format, along with the paper version printed out, because I think we're going to have to make some decisions based on those detailed assumptions.

BY CMSR. BELOW:

Q. And, what I'm wondering, Mr. McCluskey, if you could either do the same or, in a short turnaround time, once that Exhibit 10 is received, if you could, working off the same Excel spreadsheets, enter your assumptions and identify how those assumptions are different, so that

we can really see, in a final analysis, what Staff's position is and conclusion is on the cost/benefit versus the Company's.
A. And, are you talking about, I heard this conversation earlier, and you were talking about having the SAU 16 analysis redone consistent with the Stratham, revised Stratham analysis.
Q. Right.
A. Is that what you're asking me to, to redo the Stratham based on the revised analysis?
Q. Yes. And, in a sense, you've done that on I believe it's Exhibit 12 for Stratham, but not necessarily with your revised assumptions for the SAU project.
A. Correct. But my analysis for SAU 16, in the direct testimony, is very close to that, but it might need a little bit of refinement to deal with the federal tax credit and a couple of other things that, for example, how to calculate the RECs, we might need to refine that a little bit. But I can certainly do that, that calculation.
CMSR. BELOW: Okay. We'll reserve as a separate exhibit, I think we're up to 17, as Exhibit 17, that sort of parallel document.
(Exhibit 17 reserved)

CMSR. BELOW: And, if you could take the two -- the two projects and do an additive spreadsheet that just shows the two projects combined, as if they were one, and see what the overall picture is.

WITNESS McCLUSKEY: Which I actually did in the direct testimony. We looked at them both, for SAU 16 individually and on a combined basis. And, in fact, our recommendation to approve it was based on the combined. Because, as you would guess, the PV facility didn't look very good on its own. But, as a combination, we think it's a good project.

CMSR. BELOW: All right. Okay.

WITNESS McCLUSKEY: Thank you.

CMSR. BELOW: I think that's all. Do you have any redirect, Ms. Amidon?

MS. AMIDON: No, I don't. Thank you.

CMSR. BELOW: Okay. So, there's no -- you're excused then, as a witness. And, I don't believe there's any more testimony. So, have the parties -- do you have a consensus on whether you would like to do oral remarks or closing arguments or whether you would like to provide written closing arguments?

MS. AMIDON: Well, I will speak, and I will let any of my colleagues correct me if I'm wrong. We agreed we would like to provide written comments, that we also agreed to a page limit. Now, someone is going to have to remind me what that page limit is? Two pages. And, to have them filed no later than close of business Friday.

CMSR. BELOW: Is that realistic, in light of some of our exhibit requests, particularly Exhibit 10 and what's now Exhibit 17? And, I'm just wondering if it might be helpful to have those exhibits in hand, and then provide a few days after that to get the closing written arguments?

MS. AMIDON: It's almost -- well, you know, I think, as for Staff, our analysis stands on its own. I understand that you're asking for revised exhibits, but I think that the points that we raised in cross and in direct testimony would be the same. Whether, I guess what you're -- you may think that this may lead to a different result on whether the projects are economic or not or whether we would recommend them? Is that the question? Because I think -- I'm not sure that we would change our position on that.

CMSR. BELOW: No. It's just so that everyone is sort of working off the same page, and we have both projects, albeit Staff and UES has different assumptions, but we have the two different projects evaluated in different sort of stages of assumptions. And, I'm not sure everything is on a common basis internally. So, --

MS. AMIDON: Well, Mr. Epler, do you have any thoughts?

MR. EPLER: Yes, we would prefer to submit the written comments after we provide the exhibit, and have an opportunity to see how Staff's parallel exhibit --

CMSR. BELOW: And, I'm seeing other nods in that direction. So, is it -- today is Wednesday. Is it realistic to expect those exhibits by Monday or Tuesday of next week?

MR. EPLER: We will certainly push. I don't have my analysts here, so I can't confirm. I could try to confirm that later today. But we will certainly push to have it in no later than close of business Tuesday. I think that's -- Mr. Gantz did indicate it was days, not weeks.

CMSR. BELOW: Okay. Well, let's aim for, you know, and do your best to achieve close of business Tuesday. And, then, let's look for, by close of business Friday, the written closing arguments. Not this

Friday, a week from Friday.

Yes, Mr. Aney.

MR. ANEY: I'd just like to address the page count of the closing arguments. Given the complexities and intricacies of this docket, and what's being established as potential precedent, I would appreciate the flexibility of perhaps a few more pages than just two.

CMSR. BELOW: And, Mr. Mitchell, are you rising to speak or --

MR. MITCHELL: I had a separate question, if you want to deal with that.

CMSR. BELOW: Use double-spaced pages as we usually receive.

MS. AMIDON: We're going to use font size 8, no margin.

CMSR. IGNATIUS: I'm happy to see more than two. I just -- I think we very much don't want 25. I'm not sure that really beneficial. So, --

MR. ANEY: Can I suggest five or less?

CMSR. BELOW: I think five is a reasonable limit for this matter. Okay? Now, yes, Mr. Mitchell.

MR. MITCHELL: I'm trying -- the request

about the "projects being combined", are you talking -- in the SAU and Stratham, are you talking about combining those two projects in the analysis or are you talking about the SAU project, and there are elements in that project, and having them assessed separately?

CMSR. BELOW: No, I'm not suggesting that those be separately assessed, that one project.

MR. MITCHELL: Okay.

CMSR. BELOW: All I'm saying is, once you've got two spreadsheets that are set up the same way, that you just add those two together, to see, for the whole package of the two projects, what the overall cost/benefit looks like.

MR. MITCHELL: Thank you.

MR. McCLUSKEY: I didn't understand you, Commissioner, to be asking to combine two separate projects. I thought you were looking to have SAU 16, two components, --

CMSR. BELOW: No.

MR. McCLUSKEY: -- evaluated on a combined basis?

CMSR. BELOW: No.

MR. McCLUSKEY: Okay. So, you want to merge the Stratham and the SAU 16 projects in an analysis?

CMSR. BELOW: Just -- it's not really a separate analysis, it's just a summary document that would add the two separate sets of numbers together.

MR. McCLUSKEY: Okay.

CMSR. BELOW: Okay. Is everybody clear? If so, I will close, if there are no other procedural matters, I will close this public hearing -- well, I see a couple more hands raised. Oh, yes. Yes. I've got to do that. Right. Let me ask first, is there any objection to striking identification of the exhibits and entering them as full exhibits?

(No verbal response)

CMSR. BELOW: Hearing none, we will do that, and all the exhibits are entered as full exhibits, including those for which are data requests that we'll be receiving.

Any other procedural matters? Mr. Epler.

MR. EPLER: Yes. Procedurally, it may touch a little bit on substantive, and I hope you indulge me on this point. Just on behalf of the Company, I wanted to comment on the denial of PSNH's intervention motion. Just briefly on that, as Mr. Gantz pointed out, PSNH had representatives attend part of our tech session and some of the negotiations, and they were extremely helpful in working -- in helping us work through a technical tax matter. And, just as a matter of course, I have -- it's been my personal experience that utilities have tended to intervene in other utilities' dockets. And, I would just encourage the Commission to perhaps lean on the side of leniency when that happens, because there are opportunities, such as this one, where the other utility can be a benefit, and particularly when it's a matter such as this, a first impression, where there may be interests among the utilities in pursuing these kinds of projects on their own.

CMSR. BELOW: Okay. Thank you. Any other procedural matters before I close the public hearing?

(No verbal response)

CMSR. BELOW: And, note that the Commission will take the matter under advisement. Thank you. We're adjourned.

(Whereupon the hearing ended at 1:23 p.m.)