STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

December 13, 2021 - 9:04 a.m.
21 South Fruit Street
Suite 10
Concord, NH

RE: **DE 21-077**
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY:
2021 Energy Service Solicitation.
(Hearing regarding the period from February 1, 2022 through July 31, 2022)

PRESENT: Chairman Daniel C. Goldner, Presiding
Commissioner Pradip Chattopadhyay

Michael Haley, N.H. Asst. Atty. General
(N.H. Department of Justice)

Doreen Borden, Clerk

APPEARANCES: **Reptg. Public Service Company of New Hampshire d/b/a Eversource Energy, Inc.:**
Matthew J. Fossum, Esq.

Reptg. Residential Ratepayers:
Donald M. Kreis, Esq., Consumer Adv.
Julianne Desmet, Esq., Staff Attorney
Maureen Reno, Dir. of Rates & Markets
Office of Consumer Advocate

Reptg. New Hampshire Dept. of Energy:
David K. Wiesner, Esq.
Stephen Eckberg, Electric
Richard Chagnon, Electric
(Regulatory Support Division)

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

I N D E X

E X H I B I T S

EXHIBIT NO.	D E S C R I P T I O N	PAGE NO.
3	Petition for Adjustment to Energy Service Rate for Effect on February 1, 2022 *[REDACTED - For PUBLIC Use]*	*premarked*
4	Petition for Adjustment to Energy Service Rate for Effect on February 1, 2022 **{CONFIDENTIAL & PROPRIETARY}**	*premarked*
5	**RESERVED** *(Record Request of "why is the lead day so different for Large Customers compared to the Small Customers?")*	*68, 106*

P R O C E E D I N G

CHAIRMAN GOLDNER: All right. Good morning, everyone. I'm Dan Goldner, the PUC Chair. This is my first meeting as Chair. So, I hope you'll be patient as I get through this proceeding. I'm joined by Michael Haley, from the DOJ today, and new Commissioner Pradip, and, Pradip, maybe you'd like to introduce yourself.

CMSR. CHATTOPADHYAY: Sure. A lot of you actually know me. So, I'm Pradip Chattopadhyay. And happy to be here in this capacity.

CHAIRMAN GOLDNER: Thank you, Pradip. Okay. So, we're here this morning -- and I hope everybody can hear me okay? There we go.

We're here this morning in Docket DE 21-077 for a hearing regarding Eversource Default Energy Service Solicitation. My understanding is that this is the second Default Energy Service Rate filing in this docket, and that a competitive solicitation has been completed for the time period of February 1st, 2022, through July 31st, 2022. Pardon me. And that the Company has reviewed the bids and selected the lowest bidders.

Subsequent to Eversource's first Default Energy Service Rate filing, Energy raised an issue regarding the 2020 RPS costs amounting to $1.6 million. At the agreement of Energy and Eversource, that issue has been removed from this proceeding and will be heard separately on January 13th, 2022.

Eversource requests that the Commission approve the Company's analysis of the bids, thus authorizing the Company -- pardon me -- to execute the purchase agreements fully. Further, Eversource requests the Commission's approval of the corresponding tariff rates for Default Energy Service for Small and Large customers.

So, a question for Eversource, Energy, and OCA, do you agree with that summary? Is that fair?

MR. FOSSUM: This is Matthew Fossum, for Public Service Company of New Hampshire, doing business as Eversource. And, yes, generally, we agree with that summary.

CHAIRMAN GOLDNER: Okay. Thank you. Okay. Very good. Let's take appearances.

Eversource?

MR. FOSSUM: Well, once again, Matthew Fossum, here for Public Service Company of New Hampshire, doing business as Eversource Energy.

CHAIRMAN GOLDNER: Thank you, Mr. Fossum. OCA?

MR. KREIS: Good morning, Chairman Goldner. I am Donald Kreis, the Consumer Advocate, here on behalf of residential utility customers. As everybody knows, to my immediate left is Maureen Reno, who is our Director of Rates and Markets, and to her left is Julianne Desmet, who is our still relatively new Staff Attorney.

And the OCA would like to hardily welcome Commissioner Chattopadhyay to the Bench. And we would like to state for the record that we expect him to be especially hard and brutal on the Office of the Consumer Advocate.

CMSR. CHATTOPADHYAY: Thank you.

CHAIRMAN GOLDNER: Department of Energy?

MR. WIESNER: Good morning, Commissioners. David Wiesner, representing the

Department of Energy. And with me this morning is Steve Eckberg, an electric utility analyst in the Department's Regulatory Support Division.

And I also want to take this opportunity to welcome Commissioner Chattopadhyay to the Bench. It's good to see a familiar face in a new and different role. So, welcome.

CMSR. CHATTOPADHYAY: Thank you.

CHAIRMAN GOLDNER: All right. For preliminary matters, Exhibits 3 and 4 have been prefiled and premarked for identification. All material identified as "confidential" in the filings will be treated as confidential during the hearing.

Is there anything else that we need to cover regarding the exhibits?

MR. FOSSUM: I don't believe so, no.

CHAIRMAN GOLDNER: Okay. Thank you. And I have Exhibit 3 as the redacted version of the Petition and Exhibit 4 is the confidential version of the Petition.

All right. Any other preliminary matters before we have witnesses sworn in? Does anyone object to the witnesses and the prefiled testimony, for example?

[No verbal response.]

CHAIRMAN GOLDNER: Okay. All right. Let's proceed with swearing in of the witnesses, Mr. Patnaude.

(Whereupon ***Frederick B. White*** and ***Erica L. Menard*** were duly sworn by the Court Reporter.)

CHAIRMAN GOLDNER: Thank you. This is a bit of a change, but I thought I would, with the advice of the DOJ, kind of start with this before we go to direct examination, Mr. Fossum.

It's our understanding that there is, I think, five statutory considerations here today. And we just thought we would check to see if there was any concerns as we listen to the witnesses. It helps to have a proactive view.

So, we have default service, which is 374-F:3, V; consumer choice, which is 374-F:3, II; universal service, 374-F:3, V; benefits to all ratepayers, 374-F:3, VI; and appropriate recovery of stranded costs, 374-F:3, VIII.

So, I'll let -- I read that fast. So, I'll pause for a second and just see if there's anything that the Commissioners should be considering, in addition to those statutes, as we listen to the testimony?

MR. KREIS: Mr. Chairman, I would say, on behalf of the OCA, that, as with any rate that comes before the Commission for its approval, the general standard that applies is the requirement that appears in several or at least two places for "just and reasonable" rates.

I don't think we need to get into a big discussion today about the Restructuring Act. But my perspective on the Restructuring Act is that it is simply a set of instructions that guided the Commission through the process of transforming our electric utilities from their formerly vertically integrated guise, to their current embodiment as distribution companies that seek default service. And, so, I tend not to focus on the restructuring policy principles, and more on the question of "just and reasonable" rates.

But, that said, by whatever standard you apply, I think, just by way of a spoiler alert, what the Company is proposing here today is worthy of your approval.

CHAIRMAN GOLDNER: Thank you. Anything else, before we move to direct examination?

[No verbal response.]

CHAIRMAN GOLDNER: All right. Mr. Fossum.

MR. FOSSUM: Thank you. I'll begin with Mr. White, and then Ms. Menard.

FREDERICK B. WHITE, SWORN

ERICA L. MENARD, SWORN

DIRECT EXAMINATION

BY MR. FOSSUM:

Q Could you, Mr. White, please state your name, your position, and your responsibilities for the record?

A (White) My name is Frederick White. I'm the Supervisor in the Electric Supply Department for Eversource Energy Service Company. I supervise and provide analytical support required to fulfill the power supply requirement obligations of PSNH, including conducting solicitations for the competitive procurement of power for Energy Service customers. We also manage Renewable Portfolio Standard obligations, and are responsible for ongoing activities associated with independent power producers and purchase power agreements.

Q Thank you. And, Ms. Menard, the same.

A (Menard) Good morning. My name is Erica Menard. I'm the Manager of Revenue Requirements. I am employed by Eversource Energy Service Company supporting PSNH. I'm responsible for rate and revenue requirement calculations for various regulatory filings before this Commission.

Q Thank you. Now, I'll just go through a series of fairly routine questions. And I'll ask Mr. White to answer first, just to keep the record clean. Have you previously testified before this Commission?

A (White) Yes, I have.

Q And Ms. Menard?

A (Menard) Yes, I have.

Q And did you file testimony and supporting materials as part of the materials that were submitted on December 9th, 2021, and included in Exhibits 3 and 4?

A (White) Yes.

A (Menard) Yes.

Q And was that testimony and that supporting information prepared by you or at your direction?
A (White) Yes, it was.
A (Menard) Yes, it was.
Q Do you have any changes or updates to that information this morning?
A (White) I have no changes.
A (Menard) No. I have no changes.
Q And do you adopt that testimony as your sworn testimony for this proceeding?
A (White) Yes.
A (Menard) Yes, I do.
Q Now, just briefly, we'll go through a couple of things to flesh out the record.
Mr. White, could you please explain, understanding what's already in your testimony, could you please explain the Company's solicitation that led to the filing that's included in Exhibits 3 and 4?
A (White) Sure. We issued an RFP on October 28th, 2021, requesting supply for the Large and Small Customer Groups for the six-month term of February 2022 through July 2022. The request was for full requirements power supply without RPS

compliance included, which is managed separately by the Company. We solicited for the Large Group in one tranche, which averages approximately 20 megawatt-hours per hour averaged over the six-month term. And, for the Small Customer Group, in four equal 25 percent tranches, which, in total, are about 400 megawatt-hours per hour on average over the term.

Offers were due on December 7th. All bidders were prequalified with regard to their standing at ISO-New England, the Company's prior experience with those suppliers, and all posted necessary credit arrangements prior to our acceptance of their offers. The offers we received were in line with price expectations. Participation was good, making it a competitive auction. And the proposed awards that we made to senior management, and as proposed today, were based on lowest prices.

The offers and our recommendations for awards were approved by senior management on the afternoon of December 7th. And Transaction Confirmations were executed with suppliers on December 8th.

Excuse me. The solicitation was conducted consistent with past practices and with Commission requirements. It's described in further detail in testimony and included attachments, which was filed on December 9th. So, ultimately proposed for Commission approval is that Exelon, NextEra, Vitol will provide supply for the February '22 through July 2022 delivery term.

A few additional comments. You'll see that prices have increased. All energy prices have increased since last summer, which we've all experienced in our daily lives. Electric supply prices in New England have increased over 20 percent since our previous rate filing. Despite that, we feel somewhat fortunate for two reasons: First, prices had actually increased further, and had come down at the time of our solicitation. Second, our delivery term structure, which is utilized, as agreed to in the 2017 Settlement Agreement, separates January and February into different delivery terms. January and February are typically the highest priced months in New England's electric power markets. Generally, this smooths the price transition between rate periods, and, in this case, has mitigated the winter price increases. For example, our current 8.8 cents per kilowatt-hour rate for residential customers is in place through January 2022. The price increases will not be experienced by customers until February.

That concludes my remarks.

Q Thank you. And, Ms. Menard, could you, again already understanding what's included in your testimony, explain how the Company took the results of the solicitation that Mr. White has testified about and developed the rate proposal that's before the Commission this morning?

A (Menard) Yes. Consistent with the Settlement Agreement in Docket 17-113, which is the overriding principles for how we calculate the pricing for what we're presenting here today, we took the results from Mr. White's RFP, added administrative and general costs, and renewable portfolio expense costs to get a retail rate that we present here.

Also included in this rate, we present reconciliations through the current period.

However, the reconciliation is only done on an annual basis in our August rate filing. However, we do update the reconciliations to show actuals through October in this case, for reference only.

I want to also point out that this rate is a passthrough for Eversource. The Company doesn't earn money on this rate, on this program. It simply recovers the cost of administering the program. Any under- or over-collections that result from the differences between the revenue collected from customers, based on the rates that were set, and the actual expenses incurred, are reconciled on an annual basis, with interest accruing at a short-term rate, which is the prime rate in this case.

So, in my portion of the testimony, there are four exhibits. Attachment ELM-1 provides the Energy Service rate calculation for the Small Customer class, which is Rates R, R-OTOD, G, G-OTOD, and any outdoor lighting associated with those rates. Attachment -- sorry, that's Page 1. Attachment ELM-1, on Page 2, provides the Energy Service rate calculation for the Large Customer Group, which are Rates GV and LG, and any outdoor lighting associated with those rates. On Attachment ELM-1, Page 3, we provide the updated cost of administrative and general expenses associated with the current Energy Service offering. And Attachment ELM-1, Page 4, provides the forecasted working capital, consistent with the lead/lag study approved in the August rate filing.

Those four pages are repeated in Attachments ELM-2 and 3. They contain the reconciliation of prior period Energy Service costs and any over/under recoveries, and then a forecast of future over/under recoveries.

And then, finally, on Attachment ELM-4 contains the cash working capital calculations, and the carrying costs that are recovered through the Energy Service rate.

Q Thank you. And, again very briefly, could you please explain the actual rates and rate changes that are before the Commission this morning?

A (Menard) Yes. For the Small Customer class, we are presenting a weighted average fixed rate for the six-month period February 2022 through July 2022 of 10.669 cents per kilowatt-hour. This compares to the current rate of 8.826 cents per kilowatt-hour, a 21 percent increase for that component from current rates for a residential customer. However, on a total bill basis, it's about 8 to 9 percent for a residential customer. And Attachment ELM-5 provides that bill comparison for a typical residential customer.

For the Large Customer class, this is a monthly varying price class. The monthly prices range from a high of 21.425 cents per kilowatt-hour in February, to a low of in the 8 to 9 cents per kilowatt-hour range in the later months of the period.

Q Ms. Menard, you mentioned the information shown on ELM-5. Could you please explain what that attachment shows and what it demonstrates for the Commission?

A (Menard) Yes. This exhibit, ELM-5, is a rate exhibit. And it's an exhibit that we have prepared for a number of years at the request of the Commission, to provide a comparison for a residential customer. Page 1 compares current rates for a typical residential customer, and holds everything else constant, except for what's changing in this rate proceeding, which is the Energy Service rate.

As I said, this rate shows approximately a 21 percent increase, as compared to current rates, for the Energy Service component. But, overall, approximately an 8.8 percent increase in the overall bill.

Page 2 is a comparison for the same period last year as this year, so you can see a year-over-year comparison. And this rate shows an increase of approximately 51 percent, as compared to rates from one year ago, for just the Energy Service component.

And then, finally, Page 3 contains a percentage change in the Energy Service rate and a change in the overall rates as a result of the rates that are being proposed in this proceeding.

And then, finally, to round it out, there is an attachment, the final attachment, ELM-6, contains the redlined tariff update to be implemented, if this tariff is approved.

Q And, Ms. Menard, are there other rate changes or potential rate changes that might affect this analysis that you just described in ELM-5?

A (Menard) Yes. This is the first of several rate adjustments we will be presenting over the next month. Coming up soon, within the next week or so, we will be presenting a change in the stranded cost rate. And, in addition, we will also be presenting updates to the distribution portion of the Company's rate, and also the RRA rate.

So, there will be several other rate changes proposed for February 1st. However, at this time, those are not known and are not presented in this analysis.

Q And are there any other significant changes or issues in this rate filing to make -- of which the Commission should be aware?

A (Menard) Yes. As discussed in the Petition and my testimony, there is an outstanding issue related to Class III REC purchases made in 2020 for 2020 compliance, that will be discussed in a hearing next month, on January 13th. There have been no changes in this testimony and in this rate calculation associated with that outstanding issue.

Beyond that, the February rate is a --

is not a reconciliation filing. As I said, we typically do that reconciliation in the August rate filing. However, in working through with the DOE on the Class III REC issue over the summer, we did identify that there was a missing amount of $5.2 million that should have been included in the August reconciliation that was not included. And this is associated with the 2019 RPS true-up. That amount was booked on the Company's books. However, we did not include that in our reconciliation filing.

We will be including that in our future reconciliation filing. But, for this rate filing, we did present a change to our beginning balance, and for the July 2020 beginning balance that is shown on Bates Page 050.

We were not intending to discuss that during this hearing, because that's typically included in the reconciliation factor, which is not being updated for the February rate. However, we are open to discussing the issue, if interested.

Q Thank you. And, finally, for both Mr. White and Ms. Menard, is it your position and the Company's position that the solicitation here was open, fair, and competitive, and that the resulting rates proposed to the Commission are just and reasonable?

A (White) Yes.

A (Menard) Yes.

MR. FOSSUM: Thank you. That's what I had for the direct.

CHAIRMAN GOLDNER: All right. Excuse me. Cross-examination, Mr. Kreis?

MR. KREIS: Thank you, Mr. Chairman. Just a few questions for these distinguished witnesses from Eversource. Either witness is welcome to answer my questions, though I think it will be pretty obvious which witness is the appropriate one to field these queries.

CROSS-EXAMINATION

BY MR. KREIS:

Q I want to start with the selection of three different suppliers to provide default energy service for the Residential class. And I guess, maybe to lay the groundwork for that, Mr. White, could you explain why the residential load is divided into four tranches?

A (White) Based on previous experience soliciting power supply across all our jurisdictions, not just New Hampshire, but in Massachusetts and Connecticut, a similar process is used. And I think you don't want to go out for too large of a supply. There may be some companies for whom providing 400 megawatts an hour across six months is too large a bite that they may not want to take.

So, in attempting to not exclude, to make the solicitation as open as possible, we feel that roughly 100 megawatts is a reasonable size for one contracting piece. So, we break the Small Group into four equal-sized tranches.

In addition, similar thinking, that the greater volume a supplier takes on, there's volume risk and price risk when they enter into these contracts. So, the greater volume is greater risk. And it allows suppliers to differentiate between the first piece of business they take and additional pieces, and permits them to recognize that risk in their offers.

So, for those reasons, we break the Small Group into more manageable-sized tranches.

Q So, it's fair to say that, as to each kilowatt-hour or megawatt-hour of residential load that is accounted for via default energy service, each tranche counts for one-quarter of each of those units of energy. There isn't any difference between any of the four tranches?

A (White) They are entirely identical in terms of the responsibilities and obligations placed on the supplier.

Q Is it fair to say that in most of the solicitations that Eversource has conducted under this rubric, the same supplier has been the -- the same supplier has provided all four tranches?

A (White) No. Typically, there are more than one supplier. I believe this may be the first time there has been as many as three. I would say two is more typical. There have been instances where one supplier has won all four tranches.

Q Is there anything to be divined or inferred from the fact that this is the first time we have three different suppliers providing the four tranches in default energy service for residential customers?

A (White) We feel it's generally a good outcome when prices are clustered, they're fairly close to one another. That, to us, represents that it's a competitive solicitation. Everybody is kind of seeing the market the same way. It's fair and open. The fact that there are three winners in this case highlights that attribute, in that the prices across all the tranches we received, at least for the top four winning tranches, prices were very close to one another, such that winning offers were distributed among three suppliers, not just one or two.

Q And at the risk of asking you a question the answer to which is obvious, is it fair to say that the commercial load is so small that it wouldn't make any sense to divide that load up into tranches?

A (White) Yes. That's exactly right. The Large Group, as I mentioned, averages more around 20 megawatts. The bigger risk there is that perhaps some view it as it's so small that perhaps it's not worth the effort. We certainly wouldn't want to break it into smaller pieces.

Q Indeed.

A (White) And, excuse me, that's commercial and industrial.

Q Yes. I apologize. That's what I meant. The bid selection process that you undertook in choosing those winning bidders, I think I heard you say that, basically, you, meaning Eversource, chose the lowest bidder in each instance. Is that a fair statement?

A (White) Yes. The four winning supply tranches were the four lowest-priced offers received. That's because the additional criteria that we evaluate on, in those respects, our experience, their standing at ISO, in terms of operationally and financially, whether they have stepped out of bounds with ISO rules, and the ability to post proper credit to cover the risk that we and customers are exposed to by doing this amount of business with them, they essentially were all evaluated as equal on those criteria. They all qualified beyond the threshold, so to say. So, therefore, the evaluation, the end result is it's a price evaluation, and we accepted the lowest prices offered.

Q So, if I'm understanding you correctly, Mr. White, you're basically concluding that the winning bidders that you selected here are all familiar bidders, they're -- that they have a history of doing business in ISO-New England, and with Eversource in particular, and there are no concerns that might lead you to not choose them, even though they were among the lowest bidders?

A (White) That's correct. We have satisfactory experience in business arrangements such as this with all of the winning suppliers.

Q Would I be asking you to disclose confidential information if I asked you what the credit ratings of each of those winning bidders is?

A (White) I would say "yes". And, beyond that, I'm not sure I could answer the question anyway.

Q Okay. Well, then I won't ask. Except to ask you to confirm that each of those bidders has a credit rating that is acceptable to Eversource?

A (White) Yes. Basically, our credit arrangement requirements are based on credit ratings, and depending on a credit rating would determine either the amount or type of credit that may or may not be required to be posted prior to qualifying their offer as acceptable under the RFP.

Q Mr. White, looking at Bates Page 009 of Exhibit 4, which is also identical to Bates Page 009 of Exhibit 3, at Line 8 of that page you talk about "low and high factors [that you apply] to account for other cost elements". And I want to make sure that I understand what you mean by "low and high factors". Could you explain that to me?

A (White) As explained in testimony, prior to the receipt of offers from suppliers, we conduct our own evaluation based on applicable prices for the day that offers are being received. So, we believe we're looking at market prices, which are closing energy market prices from the prior trading day, we believe we're looking at the same price set, if you will, as suppliers are in preparing their offers that morning. And, so, with that information, capacity prices, as you know, are another major component of full requirements power supply, those reference prices, if you will, are established in auction. So, plain vanilla capacity prices are also known heading into the solicitation. So, those are two major components that are known parts of full requirements power supply.

In addition to that, for example, energy prices are strip prices. They represent the same megawatt amount in every hour over the whole delivery term. That, in fact, isn't what suppliers provide. They have to match the varying load hour to hour. So, there is a load-following component that increases prices.

There are ISO-New England ancillary services, automatic generation control reserve, spinning reserve requirements. These are all additional costs that ISO places on load-serving entities. And, of course, they have risk premiums and profit margins that are included. Those components are not known. They are variable. So, they are not as well known heading into the solicitation.

We have derived, from prior solicitations, based on the known components, we've evaluated what factors would be applied to those known components such that you would arrive at the winning offers. And over the course of several solicitations, the high and low factors that would equate to the winning offers from prior solicitations, they become kind of our high and low factors that are applied, and produce for us a range within which we expect suppliers' offers to fall.

In this case, for both the Small and Large supply, the offers did fall within those, that high and low range.

Q Thank you. That's extremely --

A (White) Extremely confusing?

Q No, not at all. Very lucid, actually, in my opinion. But here's the part I want to make sure I understand.

A (White) Uh-huh.

Q At Page -- again, I'm still on Bates Page 009 of your testimony. And you say, at Lines 16, 17, 18, and 19, and you're talking here about the high and low factors, they're applied, you say, "to the energy component", and then you say they "incorporate other cost elements such as hourly load weighting, ancillaries", by which you mean "ancillary services", "administrative costs of the ISO, and supplier risk premiums and [then their] profits."

I just want to make sure I understand whether you considered those factors to be just complete unknowns that you can't predict or make guesstimates about, or whether those other elements are included in your low and high factors, such that you have a feeling for where they're going to land?

And I know you covered that. I just want to make sure I understand how your analysis takes into account or doesn't take into account those other components?

A (White) I believe everything you said is true. We would have the ability, to some extent, to evaluate those components and attempt to establish a finite figure, so to speak. We don't do it that way. Based on experience and prior winning offers, they're all rolled into these factors. So, we're kind of accomplishing the same thing without a lengthier, more rigorous, but not necessarily more exact process that could be utilized.

And, you know, supplier risk premiums and profits, we can make guesses. We really don't know. Their business outlooks change, you know, month-to-month, year-to-year. So, we certainly don't know that stuff.

But we do it as you stated. Those are rolled into these factors. And we feel that it's a accurate, reasonable representation of the extent to which those things increase prices beyond straight energy and capacity components.

Q Would it be fair to say, given the market volatility that you mentioned earlier in your testimony, that it would be reasonable to expect that suppliers are incorporating larger risk premiums into their bids then they might have a year or two ago?

A (White) I would expect that to be true.

Q Would you expect that they're squeezing larger profits out of all of this, in light of the changing market conditions, or do you think their profits are contracting, if you have an opinion about that?

A (White) I honestly don't know. I would expect -- you know, you can think of it this way: If they want a -- let's just use a number of 5 percent profit, if the supplier rate is 8 cents versus 12 cents, obviously, 5 percent of a larger number is a larger profit margin. We don't know how they do that.

I suspect the increase in -- I would agree that there is -- they're exposed to more risk, and their risk premiums have gone up. I don't necessarily know whether that would be true on the profit side. It may be. We don't know.

Q Thank you. Would it be fair to say that there is a significant difference in the bid prices between the bids that were submitted for serving the Large Customer supply class, meaning commercial and industrial customers, and the Small Customer load, meaning residential?

A (White) I don't know if it's significant, but, yes. We typically find that offers for the Large Customer Group are a bit higher than for the Small Customer Group. We attribute that to -- I mentioned two risk components, primary risk components that suppliers face, volume risk and price risk.

With regard to volume risk, it's our belief that it's perceived to be greater for Large Customers. These are more sophisticated power users, who have more options available to them with regard to third party supply. They can get customized power supplies structured to suit their particular electric usage, things of that nature. So, they -- typically, there's more movement on and off of default energy service in the Large Customer Group than in the Small Customer Group, which typically is much more stable, as to whether they stay on the rate or come and go as frequently.

So, we believe the risk premiums are -- the volume risk premiums are higher, and that typically leads to higher supply rates for the Large Customer Group.

Q Looking at Bates Page 023, which is Attachment FBW-2, and there is a bunch of confidential information on that page, and I'm not going to attempt to disclose any of it on the record. But I can sort of vague it up enough to say that there seems to be a pretty significant difference between the bid prices for February and the bid prices for March. Do you have any opinion about why there's that particular price differential between February and March?

A (White) As mentioned in our opening remarks, typically, the highest prices in New England are winter months. And you could describe that as

"December through March", but it's primarily focused in January and February. And I imagine we've all heard discussions about natural gas supply constraints, pipeline constraints into the New England region in the winter, when much of the pipeline capacity goes for space heating in residences and businesses, which leaves less available for power generation than in other months. And, on very cold periods, that constraint in natural gas supply to power plants necessitates the need for ISO-New England to run less efficient generation. So, we get typically very high prices or much higher prices in January and February, and certainly in the forward markets, which we're dealing with here, that is almost always true.

So, what you're seeing is, if you look at the forward curves month by month, prices are much higher, as much as double, in January and February, then begin to drop a fair amount in March, and continue down, until you get into, you know, the hotter summer weather, which does not really approach high prices like in the winter, but the prices begin to rise again.

So, that steep drop that you see after February is recognition of those New England pipe constraints in the New England market, as shown in the forward market prices.

Q So, again, just to make sure I understand what you just said, because it was quite lucid, basically, even though all of us think of March as a wretched month for weather, for purposes of wholesale natural gas and electricity, March is pretty different from February, because we tend not to get the bitter cold in March that really makes the markets go crazy?

A (White) Yes. That's correct. The days are longer, the space heating loads drop. I think you'd see a similar, I don't know if as dramatic, but heating degree days would probably show a similar curve.

Q And just so it's clear, these contracts that you've entered into with default service suppliers are prices that are now known and fixed. So, even if it turns out that we have a super mild winter, natural gas prices continue their downward drift, and wholesale spot prices on the ISO-New England markets go down, default

energy service customers will continue to pay the prices that are reflected in these contracts?
A (White) That's correct. These are fixed prices through the delivery term.
Q Looking at Bates Page 025, at the bottom of that page, there is -- the Company has figures for the "RFP Rate Adder". Those are current rate adders, are they not? Those are actual numbers, not projections or guesses about the future?
A (White) Those are forward market prices as of the offer date. Similar to where we poll the energy market for energy prices on the morning that offers are coming due. At the same time, we look at forward prices for REC markets. All of that -- well, the REC prices we utilize are from brokers who deal in REC markets.
Q Thank you. Given that those projections date from the solicitation, has anything changed since then?
A (White) With regard to RECs --
Q Yes.
A (White) -- or energy? I don't believe so. REC markets have been pretty stable. Remember that these are 2022 prices. And, so, while there may

be some activity, there's not a lot of activity going upon in 2022. People are still managing 2021 at this point in time. So, these prices, we were looking at them leading up to the solicitation over the course of, you know, looking at them more closely, say, for a month, they didn't move a lot over that time. That have been fairly stable in these price ranges.

Q Thank you, Mr. White. I think I just have maybe one or two questions for Ms. Menard, and then I'll be done. Sorry for taking up so much time.

Is it fair to say that the proposal to have large commercial and industrial customers live with a monthly varying price, and residential customers live with a price that doesn't change through this period, is that pursuant to the 2017 Settlement Agreement that you mentioned?

A (Menard) Yes.

Q And is there any reason to revise the thinking that was current in 2017, now that we have several years of experience around whether it makes sense to continue to do it that way?

A (Menard) I suppose we could look at any time and change the methodology. I believe the thinking back then, and if Mr. White wants to add anything, he was part of that back then, the thinking was, it's -- as you can see from the monthly pricing, it goes up and down. And, so, a fixed rate, which is an average rate over that six-month period, is more of a smooth, known rate to customers, for the Residential class, which tends to, from our experience, tend to be the class that doesn't participate in a lot of third party supplier markets. Whereas, the larger, the C&I customers, they tend to be savvier, and that gives them a price on a monthly basis to compare to for third party markets.

But, you know, certainly, there's no reason why that assumption back in 2017, you know, can't be revisited. But that's the assumption that we're under today.

Q Okay. I think I'm on the home stretch now. I'm looking at Bates Page 057, which is the comparison of rates effective February 1st, 2021, and the proposed rates for effect on February 1st, 2022.

My first question, Ms. Menard, is

wouldn't you agree with me that that is a more relevant comparison than comparing the rates that are currently in effect to the rates that will be -- that you are proposing for effect on February 1st?

Maybe not "relevant", but more meaningful?

A (Menard) I would say, in general, yes, except for last year was an odd year. Because of the pandemic, the pricing was significantly lower.

So, you know, in a normal, if you were comparing year over year, you were comparing the winter term rate from last year to the winter term rate this year, I would say "yes", except for the anomalies we saw last year.

Q So, the February 1st, 2021, rate was, in your opinion, unusually low?

A (Menard) Yes.

Q And you mentioned that there is, therefore, year on year, a 51 percent increase in the Energy Service rate, assuming the proposed rate is adopted. Do you have an estimate for what the overall rate increase is, between the rates that a residential customer paid in February of 2021, versus what you expect them to pay on February 1 of next year?

A (Menard) Can you say that again?

Q I was just trying to get a feel for what the overall change in Eversource's retail rates for residential customers will be, if you compare February 1 of this year to what you are expecting for February 1 of next year?

And, you know, again, because you said that Energy Service rates are going up by 51 percent, and you pointed out, correctly, obviously, that that isn't the totality of rates that residential customers pay. So, I'm just trying to get a feel for what the overall percentage increase in residential bills will be year on year?

A (Menard) So, for right now, on Bates 057, you can see that, just for the Energy Service -- incorporating the Energy Service rate change that we're proposing, compared to last year, the increase is about 22.8 percent.

But I don't have other rate changes that we'll be proposing on February 1st known yet. So, I don't have that number for you.

Q It's also fair to say, though, that one difference between last February and this coming February is that we have wrapped up a rate case with Eversource during this period. So, there's a significant, although totally just and reasonable, increase in the default -- or, in the distribution rate, yes?

A (Menard) Well, in February of 2021, we had the distribution rate increase in effect. That went into effect on January 1st, 2021. So that one is also -- so, there's an apples-to-apples comparison.

We have had, since February 1st of 2021, there was a step increase in the distribution rate. So, that wouldn't be known in the February 2021 rate.

Q Gotcha. Thank you. I'm sorry, I slightly mischaracterized that.

And then, you mentioned that there are other upcoming rate adjustments that are the subject or will be the subject of future filings for effect on February 1. You mentioned the "Stranded Cost Recovery Charge", the "distribution step increase", and the "RRA".

First of all, "RRA" stands for?

A (Menard) "Regulatory Reconciliation Adjustment mechanism".

Q Thank you. You passed the quiz. And you said that you don't know yet what the changes in those three rates will be. Do you expect them to increase?

A (Menard) We expect the Stranded Cost rate to decrease. We expect the RR rate to be an interim rate decrease. And we expect the distribution rate to be a slight increase. Per the Settlement Agreement, we have to -- we are proposing an increase for a New Start Program.

So, in general, those will probably be a decrease to offset this increase.

Q And, finally, just so it's absolutely clear, you mentioned that there is an ongoing dispute around certain REC costs, and that those -- that dispute will be heard by the Commission at a hearing next month. In the meantime, customers, particularly residential customers, are being held completely harmless, so that, in the event that that recovery is totally disallowed, there is no way that customers will be paying those costs starting on February 1st?

A (Menard) Correct. Because we're not -- in the August reconciliation, those costs were not included. So, therefore -- and we use that reconciliation factor for a year, so until the next August reconciliation. So, they're not included in that reconciliation. We don't present anything in this rate. So, therefore, it's not in there. So, customers are not affected.

Q So, assuming Eversource prevails, not that I assume that, but just for the sake of argument, if Eversource prevails at that hearing in January, we'll see the effect of that this coming August?

A (Menard) Correct.

MR. KREIS: Thank you. Mr. Chairman, those are all the questions that I have.

CHAIRMAN GOLDNER: Thank you, Mr. Kreis. Energy, Mr. Wiesner?

MR. WIESNER: Yes. Thank you, Mr. Chairman. I do have a few clarifying questions for the witnesses. I think I'll begin with Mr. White.

BY MR. WIESNER:

Q And I'll start by picking up on a line of questioning from Attorney Kreis, about the creditworthiness of the prospective suppliers that bid in the RFP. I understand that that is a non-price criteria that's considered by the Company in effectively qualifying bidders to be considered eligible to submit bids, which will then be evaluated on a least-cost basis. Is that fair to say?

A (White) Yes. I would say that's accurate.

Q And with respect to the suppliers' creditworthiness, in fact, it is the case, as I understand it, that, if a supplier has a high enough credit rating, it may not be required to submit any additional financial security. Is that correct?

A (White) Correct. That's my understanding. I'm not a credit expert. All this is run through our credit group, and we rely on them to qualify suppliers. But that, what you just said, is my understanding. Yes.

Q And for other suppliers that perhaps have a lower credit rating, they would bolster their creditworthiness, if you will, by submitting financial security, in the form of letter of credit or some other mechanism?

A (White) Or a parental guarantee, things of that nature, yes.

Q Okay. Thank you. And, in this case, each of the bidders, as I believe you testified, met the non-price criteria, met that threshold, and therefore the bids were evaluated purely on least cost?

A (White) Yes. That's correct.

Q Thank you. And, now, I want to take you back to Bates Page 023. This is the table of RFP results. And much of that information is confidential, and I will not ask you about confidential details included in that table. But I just would like for you to confirm that the Company believes that the number of bidders for each of the five tranches was sufficient to ensure a competitive outcome?

A (White) Yes. That's how we feel.

Q And in line, either equivalent or greater than your experience in previous RFPs?

A (White) Yes. It's not the most and it's not the least. It's probably on average. And it is also in line with our solicitations conducted in our other jurisdictions within a reasonable close time proximity to this solicitation. It's what we've been experiencing recently.

Q Thank you. And therefore, it is the Company's position that the results of the RFP reflect competitive market outcomes, which are consistent with current conditions in the wholesale power market, is that correct?

A (White) Yes. That's correct.

Q Thank you. And, in part, the Company reached that conclusion by its comparison to the proxy prices, which are developed for bid evaluation?

A (White) In part. We would say that robust participation is probably the primary attribute. We don't view the proxy prices as a target. They are a guideline, a reference point that we can sort of think off of. In this case, offers fell in line with that evaluation as well.

But the level of participation and the spread of offer prices I think is what gives us most comfort that this was a competitive solicitation and produced a reasonable outcome.

Q Thank you. This is a detail question. But, in reviewing the RFP itself, and this is on Bates Page 016, there's a provision of the RFP, which I'll just read it. That's probably easiest: "[The] Supplier shall be responsible for all transmission and distribution losses associated with delivery of energy from the Delivery Points to the ultimate customers' meters."

Can you explain in more detail what additional costs would be incurred by the wholesale suppliers related to those system losses?

A (White) If you think about the power markets, for example, when your meter is spinning at home, and let's say it registers 100 kilowatt-hours. To get 100 kilowatt-hours to your meter, at the ISO-New England -- what they call the "PDF", which is -- the "PTF", which is where ISO-New England markets settle for wholesale participants in New England, to get 100 kilowatt-hours to your meter, we might have to -- generators might have to produce 110 kilowatt-hours. And that's because there's a loss of efficiency across the wires, to get it from where it's produced to where it's used. And those are loss factors. And our contracts with suppliers are at that PTF. So, they're required to provide the 110 kilowatt-hours.

We get there offers there, and we translate those offers to appropriate rates at the customer meters. In other words, we have to collect from a customer a rate based on 100 kilowatt-hours, to pay the bill that suppliers have provided for 110 kilowatt-hours. And the supplier has to pay costs associated with the 110 kilowatt-hours at the PTF. The ISO will assign costs to them on that basis.

So, that's what that section is referring to. They put it in their price, obviously. But they're responsible for providing to those volume levels.

Q And the applicable loss factors are known to the bidders when they submit their supply offers?

A (White) The applicable loss factors are not known.

Q So, is it fair to say that these additional costs and the relevant factors represent another risk that's borne by suppliers when they submit bids to the Company?

A (White) That's true. Let me qualify a little bit. We do publish loss factors on our website. We kind of wind of doing a weighted average there. So, what actually is in our rate exhibits is not a figure known to the supplier community. From their experience, from what the information we do post on the website, they begin to get an understanding. But that's sort of how that fits together.

So, yes. That's an unknown that they need to predict somewhat. Although, you know, I'm going to back up a little bit. Historically, they know loads for small and large customer groups at the ISO-New England PTF. So, I guess, at the end of the day, they're not that concerned with how we translate their prices to rates at the meter.

So, I'm going to back up a lot, and say that risk is really more on customers. It will be reconciled after-the-fact.

Q I guess where I was going is to try to explore whether that might be an additional cost and risk that suppliers would build into their risk premiums, which also might result in a price that appears to be higher than what the competitive wholesale market would otherwise generate? Effectively, it becomes a component of what you've characterized in your testimony as the "energy price bid multiplier"?

A (White) I'm going to say essentially not. Because they know historically loads at the PTF, so they have to forecast what they believe loads will be going forward. But the loss translation to the customer meter is not an issue they need to deal with. Sorry for the confusion.

Q Thank you. I appreciate that clarification. That's helpful.

I'll now turn to Ms. Menard. And I guess I just want to follow up somewhat on the missing $5.2 million. This is Bates Page 050, which is the Company's current schedule of RPS Revenues and Expenses Reconciliation. Again, this is provided at this point for informational purposes, because the reconciliation takes place on an annual basis in conjunction with the August filing, is that fair to say?

A (Menard) Yes. That's correct. So, on -- sorry,

did you want me to explain it?
Q Well, I just -- on Line 9, we see the "Ending Monthly Balance". And that, on Bates Page 050, is shown as a "negative $3,978,000", is that right?
A (Menard) That's correct.
Q And that represents an overpayment that would be credited to customers when RPS expenses are reconciled?
A (Menard) Correct.
Q And that value is different than the value that was included in the schedule most recently filed by the Company in connection with the reconciliation that occurred earlier this year?
A (Menard) Correct.
Q And you mentioned that the -- yes, I think it's fair to characterize your testimony as suggesting that that was just a mistake that it was not included?
A (Menard) Correct.
Q And it might have been included, because it relates to 2019 RPS compliance, is that correct?
A (Menard) Yes.
Q Okay. Thank you. And just to confirm, using the

lower value for the RPS payment -- RPS overpayment, excuse me, in the reconciliation, would result in a higher RPS adder when ultimately reconciled, all else equal, is that correct?
A (Menard) Yes.
Q Thank you. And I guess I'll finish by, well, two more questions. I'll draw your attention to Bates Page 042. And here the Company -- here it's your testimony that the Company's plan is to reconcile any disallowance related to the Class III REC purchase expense in the annual reconciliation for the August 2022 filing?
A (Menard) That is our proposal, yes.
Q Would it be possible to implement that reconciliation, if the Commission were to order a disallowance for the February 1st Energy Service rates that we're discussing today?
A (Menard) Anything is possible. Yes.
Q All right. Thank you for that clarification. But it is the Company's proposal to differ that reconciliation until the annual reconciliation, which takes place mid-2022?
A (Menard) Correct.

Q And I guess I'm a little -- well, I'm a little confused about the Class III REC purchases from last year, and whether the full amount of those purchases is currently included in the Energy Service rates. Is it -- whether as an estimate or actual, and subject to reconciliation, are customers now paying for the full amount of expense that the Company incurred to comply with RPS for the calendar year 2020?

A (Menard) So, the way that we estimate RPS expense is we don't know the full amount of RPS compliance until June of any particular year, when the E-2500 is filed.

But between -- but you don't want to put all of your expense in one month. So, we estimate, using the RPS adders that you see in our filing, and we estimate based on sales volumes, multiplied by the RPS percentage, multiplied by the RPS adder, and we come up with an estimate. And that's a liability to the Company every month. So, we book an accrual every month. So, that's our RPS expense estimate every month. And, come June, we take that calendar year estimate, and we reconcile that against our actual RPS compliance expense. And there is a variance; it could be higher or it could be lower.

So, if you go back to calendar year -- I'm going to get there myself. So, if we go back to calendar year 2020, we estimated the calendar year. We filed our RPS reconciliation in June of 2021. At that time, we did not know what the full RPS compliance expense would have been for calendar year -- or, for -- yes, for calendar year 2020. So, there's an estimate in there. Once we know that amount, we reconcile it.

So, this Class III RPS expense issue relates to 2020 Class III RPS expense. We have estimated that expense based on the RPS adders, not actuals. So, that's why I say it's not included in that RPS reconciliation until you fold in the reconciliation amount in June.

Q Okay. That's very helpful. So, just to clarify to the nth degree, the actual Class III REC purchase expense for calendar year 2020 has not been reconciled to be included as such in the RPS adder?

A (Menard) Correct.

Q Okay. But now -- and the Company's proposal is to do that, pending the outcome of the hearing, and the decision will be made by the Commission following that hearing, --

A (Menard) Correct.

Q -- on this issue in January, for reconciliation on the annual schedule for the August 1st rates?

A (Menard) And that's why I propose it to be done in the August timeframe.

MR. WIESNER: Thank you. Appreciate that.

And no further questions for these witnesses. Thank you, Mr. Chairman.

CHAIRMAN GOLDNER: Okay. Thank you, Mr. Wiesner. Commissioner Chattopadhyay.

CMSR. CHATTOPADHYAY: Mr. White, I'm going to first address my questions to you. If you think that the other witness is better able to answer, please let us know. So, I'm going to just ask some general questions first. Sorry.

BY CMSR. CHATTOPADHYAY:

Q So, at Bates Page 005, Line 21, and you don't have to necessarily look at it. I was just letting you know. You have indicated that 45 percent of the Eversource load is currently -- just want to make sure the mike is on -- is currently with the Company's Energy Service. Can you provide a brief description of how this percentage has evolved over the last three years or so?

A (White) I guess, over the last three years, I don't think there's been significant changes. Going from memory, I would say that only about 5 percent of industrial load takes Default Energy Service, only 15 percent of commercial load takes Default Energy Service, and about 85 five percent of -- 85 percent plus of residential load takes Default Energy Service.

Over the last two or three years, I think it's been in that range. You'd have to go back further where you can see the, you know, larger changes in those values occur year to year.

Q Since you mentioned that, can you give me a sense of, like if you go even back -- even further back, what the percentage was? Was it -- roughly would be good enough?

A (White) Well, I would say that industrial load was the first that third party suppliers aggressively marketed to. So, they were the first group that left Eversource supply. I think you'd probably have to go back, you know, I'm not that good with dates and recalling when competitive markets were open, but you would probably have to go back 15 years for there to be a significant amount of industrial load being served by PSNH.

Residential load, probably within the last decade, was virtually 100 percent served by PSNH. And there was a point in time where marketers saw the opportunity to serve residential load, and probably over a year or two most of that decrease from 100 percent occurred. And it's sort of stayed fairly stable at 85 to 90 percent since then.

Q Thank you. I think you mentioned this, I just want to confirm. When you -- this relates to the questions about the tranches for the Small Customer Groups -- Group, rather. There is nothing specific about what the customers do there, as far as, you know, the choice of the tranches, it's -- I'm not talking about the percentage, I'm talking about even the four tranches somehow having been determined based on -- it's going to target different customers, that's not what it is about. It's simply, when you look at the prices, they might be different for the different tranches. That's purely the supplier's strategy, right? I mean, it has nothing to do with customers?

A (White) It has nothing to do with customers, you're correct. When our transactions with suppliers, the invoicing and payments, are based on the price per tranche. When we calculate rates, they are four equal tranches. We call it a "vertical slice", not a "horizontal slice". It's simply the average of those four prices, because they are entirely equivalent, blended into one rate for the entire group. It has no impact to customers whatsoever. They are blind to the tranches and the differing prices.

Q Some of these questions are really I'm just trying to make sure I'm following the filing fully.

A (White) Yes.

Q So, maybe kind of, for you all, that's there in the testimony, but I just want to make sure that I'm getting it. So, you talk about the MPSAs.

A (White) Yes.

Q And, so, they haven't undergone any change this year or this solicitation. It's the same that was there previously?

A (White) That's correct. We executed MPSAs, Master Power Supply Agreements, with all of these suppliers sometime previously. They have not been altered.

Q Okay. So, I'm going to go back to I think the Consumer Advocate was, I think it's Bates Page 009. So, let's just go there.

So, I would like to understand how the factors may have changed this time around relative to what it was, say, last time. Did it change much?

A (White) Oh, you're taxing my memory. One of the factors changed this time around slightly. And I'm fairly certain that it was a low-end proxy, which we're probably, in this environment, not as concerned about. But, again, we like to kind of provide reference points for us to think from.

So, I believe the answer to your

question is "yes". One of the proxy -- one of the lower ranges went down a little bit. Just remember that the proxy, those high and low proxy prices are based on prior winning offers. So, we're not looking at what the proxy would be for an offered rate that lost, that didn't serve customers. So, that's why we use a family of rates from several prior solicitations.

And, so, what that, in plain language, what that means is that the last set of offers that we accepted in the last solicitation, one of them was fairly low, and actually resulted in a reduction in a low-end proxy price.

Does that answer your question?

Q Yes, it does.

A (White) Okay.

Q That's helpful. So, you talked about the -- you know, you sort of used eight RFPs to update the factors. You mention it somewhere in your testimony. What is the sample size right now that you relied on to -- I mean, I know that, depending on different solicitations, you may have had just one winner or two winners or three winners, you know, I don't have a sense. But what is the sample size of the observations that you relied on this time around?

A (White) Well, again, as stated in testimony, as you stated, we have evaluated all of the eight prior solicitations in New Hampshire. You may recall that, when we first began this in New Hampshire, obviously, we didn't have any experience specific to New Hampshire. So, we kind of borrowed factors from our other jurisdictions to get started. As we progressed through time, we got to a point where we believed there was sufficient "New Hampshire only" information for us to utilize. So, we've used the eight prior solicitations, and Large and Small are evaluated separately.

So, there's two ways to look at it. We only use the winning offers. So, for the Large Group, we have a family of eight winning offers from the prior eight solicitations. That would be the sample size directly.

But I think part of your point is that we may have had multiple bidders that you could also create factors from. But we throw those out, because they are losing offers, okay?

With regard to the Small Group, where we have four tranches, we utilize the winning blended price to calculate the factor. So, we're not looking at -- in this case, there were three winners. We're not looking at the lowest offer. We're looking at the blended winning price to develop the factor. So, that's how that's done.

So, I think the answer to your question is that the dataset is eight for both Small and Large. And there is a question, "do we continue to accumulate more and more?" We may not go beyond ten. We'll have to think that through. But we're probably at a point in time -- you get to a point in time where, as data becomes dated, you know, markets change, the configuration of the system changes, risk profiles change. Is it valid to continue to use figures that become four, five, six years old? We have to think more about that. But, to date, we've used all New Hampshire solicitations in the dataset.

Q Thank you. That is helpful. So, really, what you're doing is you're looking at the blended numbers. And, so, that's why you have eight regardless?

A (White) Yes.

Q Okay. This is -- I'm just trying to be absolutely clear, as I understand what you mean when you say "then-calculated energy component"? This is Line 22, Bates Page 009. Does that -- that doesn't include the ancillary services and all of those? This is just the energy?

A (White) That's correct. But, Commissioner, that's really a function of mechanics. That, when we're doing the algebra, so to speak, we base the factors on the energy component. We feel that's probably the most -- well, it's really a matter of mechanics.

We could base the factor on a combination of energy and capacity. We don't. We do it on just the energy component from that point in time.

Q Yes. I wouldn't want you to assume that there was anything, I was sort of suggesting this is how it should be done. I was simply trying to understand the mechanics of it.

So, really, I'm trying not to get into any confidential information. So, the way you have constructed the factors, I would assume that they would almost always be greater than one. But have there been instances, because of pure calculations or for whatever reasons, that you've gotten numbers that are not so?

A (White) No. They have always been greater than one. And -- yes, they have, I think, and they always will be greater than one, because they are -- they represent real additional costs, real additional risk. I don't think anyone would -- a supplier would never calculate a negative risk. So, I believe that they always have, and I believe they always will be greater than one.

And I want to qualify something. It's subject to check whether, for the Small factor, we're using the blended price or the lowest winning offer. I really have to go back and ask the folks that actually do this calculation for us. I'm not in that detail. So, I want to -- I believe I answered accurately, but I may be wrong. So, I just wanted to point that out on the record.

Q And, if you are -- if you find out that you misstated it, please let us know. You know, we can at least know exactly what the right answer

was.
A (White) We can do that. Yes.
Q Can you explain a little bit about "rating limits"? I just want to understand it.
A (White) Restate that please.
Q Can you explain a bit about -- you have used the term "rating limits" in --
A (White) "Rating limits"?
Q Yes. Let me just go there. Maybe it's -- it's where you were looking at the creditworthiness. There was an attachment. If you don't know much about it, that's fine. I'm just curious what that means.

MR. FOSSUM: If I may help, is the Commissioner referring to the "Credit Exposure Limits" on Bates Page 022?

CMSR. CHATTOPADHYAY: Let me confirm. Yes.

BY THE WITNESS:

A (White) I think what this table is representing is that, based on varying credit ratings, leads to varying qualified, unsecured credit limits. So, if you have a very high credit rating, our Credit Department has said that you are -- our exposure to you could be as high as $30 million in unsecured credit.

BY CMSR. CHATTOPADHYAY:

Q So, I think the term "rating limit" is -- you're sort of using it as the same as "unsecured credit limit"? That's what you --

A *(Witness White nodding in the affirmative).*

Q Okay. I wasn't sure about that. Again, I'm not 100 percent sure whether you will be able to answer this, or, Ms. Menard, if you are the one who's going to respond, but let me just ask the question.

I've looked at the working capital Excel file, which is, I think, 4, number 4, right? It's -- I've noticed that the difference between Small Customers and the Large Customers is really about the lead days. And do you know why the lead days is so much higher for the Large Customers? I just want to get a sense.

A (Menard) I would have to go back. I don't have it with me, but I would have to go back to the Lead/Lag Study that was filed in August that develops the lead days. It's a difference between when we pay the invoice and the services are incurred.

We would have to go back and look. I don't have the information with me, unfortunately.

Q I'm just asking because I want to understand, that's all. And is it like typical? Like, you know, so maybe that that is typical, usually that's what happens. So, some explanation would be helpful.

MR. FOSSUM: So that I am clear, is that to be taken as a record request for this hearing?

CMSR. CHATTOPADHYAY: Yes.

(Cmsr. Chattopadhyay and Chairman Goldner conferring.)

CMSR. CHATTOPADHYAY: So, I'm going to repeat the question here, just to make sure people have it right.

So, as I understand, looking at the Excel file, the difference between the Large and Small Customers, when looking at the working capital percentages, is really driven by the lead days.

And, so, my question is, why is the

lead day so different for Large Customers compared to the Small Customers?

BY CMSR. CHATTOPADHYAY:

Q As you were going, you know, through the answers to the previous questions, it just occurred to me that, for the Large Customer solicitation, roughly, you're sort of going for I think I heard "20 megawatt-hours" or something for the month. Is that what you meant?

A (White) Yes.

Q And you have already explained why it has gone down significantly, because initially I'm assuming it was above 15 percent. It was quite a bit. So, it went down. Have you given any thought to, if that was also subsumed in just one solicitation with four tranches, so, all it becomes part of the residential mix as well, I wouldn't call it "residential" then, but how -- what would that do to the quality of the solicitation, the competitiveness, and what would happen to the prices? Have you -- do you have any sense of that?

A (White) My sense would be that you'd effectively wind up with blended rates, so that residential rates would go up and industrial rates would go down *pro rata*. So, I -- we would not recommend that. I don't think, for example, the OCA would like that idea.

But I do believe it's a, you know, suppliers incorporate risk on a qualitative and quantitative basis. At the end of the day, it's a quantitative game. And I think you could sort of view it as whatever money for -- to cover the risk that are in the Large supplier rates are going to be blended in with those same components in the Small, the offers for the Small Group, and, you know, spread over a larger volume, but that money is going to be in there. But the higher risk premiums, so to speak, are -- the suppliers are going to only want to take on those risks, they would want to cover those risks with dollars. So, I think you could view it that way.

I don't think including that, those increased risk components into the -- in with the Small tranches would discourage participation. So, to the extent suppliers are more or less interested between the Small and Large Groups, I think you'd kind of wind up with the level of interest we currently generate for the Small Group, if that makes sense.

But I think that -- I think I'll offer those thoughts.

Q Thank you. I think I understand the point. I mean, the flip-side could be that, whenever you are running an RFP for a very small amount, in itself that could be also a problem. But I understand your answer.

A (White) Yes. Your point is well-taken. And I think, in the Settlement Agreement, and the significant amount of discussions that took place at that time, parties agreed that it was a better approach for the markets and from the customer viewpoint to do it as we currently do.

Q I'm skipping one question here, because you have already answer it before.

So, I'm going to go to Erica Menard. I'm going to just ask a couple of questions.

I just want to understand what happened between, let's say, August 1st, 2020 and 2000 -- sorry -- August 1st, 2021. Can you give a sense of what -- how the rates changed? And I'm more focused on the supply charges.

A (Menard) Are you referring to a particular exhibit?
Q Not really, because, in your exhibits, you are comparing February with August, and then you compared February with February last year. But those are 2022 compared to 2021. I'm asking for August 2021 compared to August 2020. Do you have -- this is, I mean, just pure curiosity. I'm just --
A (Menard) For all rate components or are you talking energy supply in particular?
Q Energy supply in particular.
A (Menard) I don't have any exhibits in front of me. But I'm thinking we might have just some information off the top of our heads. I recall August 2020 was --

(Witness White and Witness Menard conferring.)

CONTINUED BY THE WITNESS:

A (Menard) I'm trying to recall a chart that we had put together, which shows the Energy Service prices over time. And we saw a dip in the August 2020 rate, and then we saw it come back up a little bit in February, which you would normally see that. And I believe it was during the pandemic time. So, August 2020 was lower than normally would have been, because of lower loads and lower energy market pricing. So, we saw prices dip in August of 2020, and then start to come back up.

And Mr. White is confirming that we saw a rate in August of 2020 in the 7 cent --

A (White) 7.1.

A (Menard) -- 7.1 cent range, for Small.

BY CMSR. CHATTOPADHYAY:

Q Thank you. Again, this is sort of almost like developing fast in my head here. So, I just want to go back to Bates Page 050. And let me know when you're there.

A (Menard) Yes. I'm there.

Q In the back-and-forth with Department of Energy, were you essentially saying that the number that shows up in Line 9 -- 9 rather, 3,978,000, that would be replaced with some other number. Is that what you were saying?

A (Menard) The "3,978" is the replacement number.

Q Oh, that is the replacement?

A (Menard) Yes.

CMSR. CHATTOPADHYAY: Okay. Thank you. I just wanted to make sure.

That's all I have right now. Thanks.

CHAIRMAN GOLDNER: Thank you, Commissioner Chattopadhyay. I have a few questions.

BY CHAIRMAN GOLDNER:

Q First, during Mr. Kreis's questioning, he was asking about the big customers being month by month and residential customers being sort of the average over the six months. Do you have a -- does Eversource have a preference? Is there something you would want to implement that's different than what you currently have?

A (White) I would say no. I think the Company is satisfied with the way things are currently structured.

Q Okay. Thank you. Before Commissioner Chattopadhyay was asking you about the Large and Small Customers being quoted separately, my question is why? What was the history on why Large and Small Customers are quoted separately in the first place?

A (White) Frankly, when we were in the paradigm of owned generation, and Default Energy Service was one rate, going back aways, one rate for all customers. And, when my migration that we also spoke about began to occur in larger numbers, it became apparent primarily that fixed costs began to be spread, fixed costs of an owned generation fleet began to be spread over fewer megawatt-hours. And, since it was large customers who were typically leaving, they were avoiding those costs, and primarily residential customers who remained began to pick up a greater and greater share of those costs. So, it began to be viewed as a weakness in the rate structure. And, in fact, some in the room may recall we established for a period of time what was called an "Alternative Default Energy Service" rate, which was structured as a monthly rate, such that, when large customers came back to default service, they didn't come back to the term weighted average fixed price, which, obviously, when you have a flat rate over six terms -- six months, in high-price months, they're going to come and take that rate, and, when market prices drop, they're going to go into the market. We set that rate so that, when they came back, they got a current market price. They didn't necessarily -- so, I think, historically, it was long viewed as blending all those customers together in one rate didn't properly or fairly allocate costs among customer groups.

And, so, at the time of divestiture and establishing a new paradigm, all the parties involved agreed to use the structure we're currently using. And I would -- nothing is true across-the-board, but I think that's a fairly common structure throughout New England in these competitive-type sourced market structures. I know, for our Company, it's similar. Some jurisdictions have even a further breakdown beyond two groups.

Q Because where I'm going is that, if my math is right, which, you know, please check it, but about 95 percent of the load is small customers, about 5 percent is large customers, if I've done the math right. Which means, if you just moved the large customers into the four tranches, it wouldn't have a material effect probably on the quote that you get. Would you agree with that?

Or would that be, if you just took the big customers, put them in with the small customers, divided into the four tranches, do you think you'd get about the same quote from the market?

A (White) Well, I think it would be -- you could view it as blended as you've proposed. I'll offer a couple additional thoughts.

Other parts of that discussion revolved around the idea that residential customers don't want a different bill rate in the bill they receive at their house every month. It's confusing, unnecessarily cumbersome in budgeting and so forth. That's another component. It's not necessarily a dollar, it's just that was viewed -- a stable rate for residential customers was viewed as a positive attribute.

I think, so that the question to your hypothesis might be "would rates then convert to a monthly rate to prevent the type of game playing that industrial customers have the ability to engage in?" Or, would they be able to come and out of the default rate against that term weighted average flat price, where they would leave during low-price months and come back during high-price months?

And, so, those -- thinking about those components were a factor of those discussions as well.

Q Yes. My logic is just to see what I can do to reduce rates overall for New Hampshire. The OCA is representing the residential ratepayer, appropriately so, and is -- and we have, I think, the lowest possible rate for residential ratepayers, and that makes sense. I'm just looking to the future to see if there might be another model that might make more sense, looked at in the aggregate from New Hampshire to see if we can secure an overall lower rate. So, that's the line of questioning. So, I think I understand.

A (White) Well, I think, as you stated, I don't know that doing that would lower prices overall. I think you'd have the same amount of dollars just blended into a single rate.

Q Yes.

A (White) And then, it's "how do you structure rates at the customer level?" Where, currently, Large Customers pay a monthly rate, Small

Customers pay a flat rate over six months.

Q But you could change that. I mean, collectively, we could all change that, if we wanted to.

And then, and this is just a question for understanding, so, I'm thinking in terms of electrons, right? You have big customers, small customers. You're quoting, you have, basically, five tranches, four for Small Customers, one for a Large Customer. I don't -- I don't understand why, if we put the Large Customer into one of the four -- into the four tranches, right, you just divided it up, why a -- why a bidder wouldn't give you exactly the same price as they gave you today? I know big customers can move in and out, and there's some risk premium, but it's only 5 percent on 95. So, I'm just thinking it's a relatively small impact.

A (White) But it's not zero --

Q Yes. It's not zero.

A (White) -- is my point.

Q Yes.

A (White) And I would propose that they would put that money in. It would just be --

Q It would just be spread out, yes.

A (White) It would be spread out, but it would be there.

Q That's fair.

A (White) And I think some stakeholders could legitimately argue that position.

Q Yes. Do you have a modeling group at Eversource that would do this kind of thing, because I'm interested in what the models would say? Because you're doing it a certain way today, and it's in the Settlement Agreement, and everyone's agreed; no problem. I'm just wondering, if you did move to the different model, if it made a 0.0001 percent difference, I think we could all agree to go a different direction. But, if it's a material difference, which is your point, then I can understand why the Office of Consumer Advocate would object to residential rates being increased.

Do you have any kind of modeling group that does this kind of work or --

A (White) We don't have sophisticated modeling, *per se*. I think our first cut at it would be sort of what we discussed. I think it's FBW-2 that shows the winning offers, and it shows some dollar

amounts. So, it shows the ultimate Small rate paid to the winning Small suppliers.
Q Right.
A (White) If you added in the dollars from the Large winning tranche together, and added the loads together, and divided, I would agree, I think it would be a --
Q A very small number.
A (White) -- a very small number.
Q Yes. I agree. Thank you. No, that is very helpful.

I want to move on or over to RPS. So, I'm looking at, I believe, Bates Page 025, so it's off my screen. Yes. It's Bates 025. And I did some math, and I wanted you to check my math, and Mr. White or Ms. Menard, either one is fine to answer.

I calculated that the current six-month impact of RPS is 7.4 percent. And I did that by dividing 0.794 into 10.669 to say that's the impact. So, in other words, a ratepayer in New Hampshire is going to pay a 7.9 percent premium, because of the legislation that Eversource implements that says that you have this RPS

requirement. Is that fair so far?
A (White) Yes.
Q Okay. And then I did another calculation that said, okay, if we take the number of RECs that are required, which is 387,000, and I multiplied that times the weighted average of dollars per REC, I get about $13.7 million, in terms of the dollar impact. So that that 7.4 percent equates to $13.7 million. And that's, of course, a six-month impact. So, the impact, on an annual basis, would be something like double that to the New Hampshire ratepayer. Would you agree with that math?
A (White) Yes.
Q Okay.
A (Menard) And I just want to point you to, you know, you can actually see RPS expense, you know, in one of my exhibits. You can see it's, you know, for a 20 -- you know, for a twelve-month period, you know, 26 million. So, --
Q Yes. Thank you. Thank you. I did miss that in your exhibits. So, thank you. That would have saved me a lot of time with my spreadsheets. So, I'll have to read more carefully next time.

And I just wanted to also confirm that this is applied to all ratepayers? So, low-income ratepayers, everyone pays this RPS premium, correct, in the gross rate?
A (Menard) It will be anyone who takes Energy Service.
Q Understand. Yes.
A (Menard) Yes.
Q So, low income, medium income, high income?
A (Menard) Yes.
Q If you take Energy Service, you would pay for it. Okay. So, it applies to everyone.
And this might appear to be a trick question, it's not meant to be. If the Legislature were to remove the RPS, and I'm not saying they would, just hypothetically, would customer rates go down by this same $27 million? It would just disappear, right? There's no other obligation or implication from the RPS rate?
A (White) That's correct.
Q Correct? Okay. Thank you. Okay. A couple more math questions on RPS. And again, this is just in the spirit of making sure that I understand the impact. And I'm interested in the cost of

renewable power sources versus what I'll call "conventional" power sources. So, I did some more math. And, if I used 100 percent for the RPS rate, as opposed to 22.5 percent, so the statute says "22.5 percent has to be RPS" today, and if we said it "has to be 100 percent", that was the new legislative requirement, I get that the cost to the New Hampshire ratepayer would increase by 36 percent.

You could do that different ways, but I want to give you a chance to sort of compute that. Would you agree with that calculation? I can walk you through the computation, if that's helpful?

A (White) Yes. But maybe that -- so, you're at 26 million for roughly a quarter. So, you're over 100 million for 100 percent? Am I in the ballpark?

Q I'll do it -- I did it a couple different ways. I think this is the easiest way. If you take 10.669, and you subtract the 0.794, so we get that Eversource would have charged 9.875 cents to the New Hampshire ratepayer, if it wasn't for an RPS requirement. And then, you look at the RPS requirement, which is about three and a half cents. So, three and a half cents divided by 9.875 is 36 percent.

A (White) Where is the three and a half percent -- the three and a half cents?

Q That three and a half cents, that comes from the -- I'm taking the weighted average of the dollars per REC. Sorry to throw the math at you at the last minute here, but --

A (White) Is that the 0.794 divided by 22.5 percent or whatever?

Q Yes.

A (White) Yes.

Q Yes.

A (White) Okay. I'm with you.

Q Okay. So, when I do that math, I say "well, it's about, you know, $60 million annualized. It's about a 36 percent increase." And I'm just trying to understand for the general public what the impact is of the RPS on the rate that Eversource charges. So, you're just implementing the rate as the Legislature has said. I'm just trying to quantify it.

So, if you want to take back my --

because this may show up in our order, so, if you want to take back the calculation, to make sure that we're getting it right. I'm getting a 36 percent -- I'm getting a 36 percent impact due to RPS, if it was 100 percent RPS, at the top level.

So, I just want to, again, for the general public, I want to make sure everyone knows what the impact is. It's not good or bad. It's just that's the impact.

A (White) And that assumes there's sufficient renewable generation to serve that volume of load.

Q Correct. Correct. Which I think a lot of people assume will happen over time, yes.

A (White) Over time. Okay. Yes.

Q All right. Thank you. So, a question for you, Mr. White, Exhibit 3, Bates 010, for Class I RPS requirements, you described the arrangement with Burgess BioPower and Lempster Wind. How does the cost of the Class I in this arrangement compare to the market price?

A (White) It's, I would say, significantly higher.

Q Do we know how much higher?

A (White) Roughly $55 versus the $38 seen in the exhibit we were just looking at.

Q Okay. So, 55 versus 38?

A (White) Yes. Current market, --

Q Yes.

A (White) -- for Class I, is roughly 38. That number can move around a fair amount. But that's kind of a current view.

Q Okay.

A (Menard) And we would explore that in the Stranded Cost rate. How it works is, we purchase these under a power purchase agreement. We transfer what's needed from stranded costs to energy service. So, we have more RECs than we need, we might sell some, and, you know, credit customers back. But then, there's going to be an amount left over, and that's in the Stranded Cost rate. But this difference that Mr. White is talking about is the difference between what we pay them at per the contract and what we transfer them at to energy service per the market price.

Q Okay. Okay. And check me on my math here, but I'm looking at, for the Class I requirement, today is $6.7 million in this agreement. If I change the $38 to $55, it goes to 9.7. So, that's right at a $3 million impact. Is that fair, you know?

A (White) But, to Ms. Menard's point, that $3 million would show up in the SCRC rate.

Q Fair.

A (White) Right?

Q Yes. Yes, I'm just trying to understand the impact. Thank you.

A (White) Yes.

Q And then, also I think on the same page, Mr. White, you talk about the REC amount from these sources may be more than -- my notes say "more than to meet the energy service obligations." Can you talk about the scale and scope of the oversubscription? Is that what we just described?

A (White) Yes. If we go back to Bates 025, --

Q Okay.

A (White) -- the Class I requirement for six months is 177,000 Class I RECs.

Q Yes.

A (White) Times two would be 350 something thousand *[sic]* RECs. We purchase, through the power purchase agreement, 400,000 in a contract year.

Q Okay. Okay. Thank you. Okay. I want to follow up, just a couple more questions, I'm going to follow up a little bit on a question from earlier --

A (White) Excuse me, if I might, Commissioner?

Q Sure.

A (White) 400,000 from the Burgess PPA. We purchase -- Lempster generates an additional 65,000, which we take 90 percent of that 65,000.

Q Okay.

A (White) So, it's really the sum of those numbers. Sorry, I forgot that. So, it's more like 450, 460,000, in that, the volume of Class I RECs that we acquire via those two purchase power agreements.

Q Okay. As compared to 375 or something like that?

A (White) Correct.

Q Okay. Thank you. All right. So, Exhibit 3, Bates 007, you describe the Energy Service process and boundary conditions. Are there, it's kind of a follow-up on my earlier question, are there any constraints, rules, boundary conditions imposed by the New Hampshire PUC that causes rates to increase? Is there anything you could think of that would help us reduce overall rates?

A (White) Well, we could probably talk about a lot of regulations.

Q Well, I'm interested in that, you know.

A (White) I'm not as involved in those. That's why I gestured to Ms. Menard if there's anything that she might want to add.

The issue that we've discussed frequently is the timing between supplier offers and final approval of the contracts by the Commission. And suppliers offer a fixed rate, so they have that market price exposure. And the shorter the timeframe between -- the shorter the timeframe they have that price essentially open to market price changes increases their risk. And we've discussed it. And I think, from an administrative viewpoint, we've probably got it about as streamlined as we can.

I would also hypothesize that suppliers have a high amount of faith in the process, and can see how we conduct business, how it's presented through this regulatory process, and the reasonableness and fairness of the New Hampshire Public Utilities Commission. So, I would hypothesize that, when we pick up the phone and tell the winning suppliers that they have won, to a large extent, they go hedge that contract at that point in time. We receive offers at 10:00 a.m., and we promise to notify them by 3:00 p.m. that afternoon. We typically notify them between 1:30 and 2:00. So, we try to, as soon as we get senior management approval, we let them know. And we believe they begin their hedging strategies, their risk management strategies at that point in time. Nevertheless, the contracts, it is stated that it's not final until you all issue an order.

So, there's those timeframes that, to the extent they could be reduced or modified, again, how significant that would be? It's hard to say.

I can't really think of -- other than that, and I would add, Commissioner, that some jurisdictions have a shorter turnaround time, some may be longer. But those timeframes are fairly typical. Some jurisdictions do not require a public hearing, so that timeframe may be shorter. But I think the trust in the process is a major factor.

A (Menard) Some of the other things we've talked about in the past, you know, instead of individual companies doing this, is there a statewide program, you know, offering that could be done, you have larger buying power. You know, could that lead to lower prices? Perhaps.

But, you know, in terms of peeling apart what the Energy Service rate is for Eversource, it's largely the RFP results from wholesale supplier bids and RPS. RPS is, you know, the regulation component. So, if that could be reduced somehow, that would lower rates. You know, so, thinking of those two things, I mean there's some administrative costs, which are very minor. But it's largely the wholesale prices and the RPS requirements.

Q Thank you. When I was reading through the transcript, one thing I didn't understand or see was that, when you get these quotes in, is it all natural gas, nuclear, *etcetera*? I mean, is it -- it's all conventional sources, because are we double-counting the RPS somehow?

A (White) Well, no, we're not double-counting RPS.

It is a stand-alone regulatory regime. I guess I would say that we don't distinguish electrons in the power supply we buy, and it's bought at a market price. And the suppliers that we buy from may or may not own generation in New England, they may or may not own renewable generation in New England. But they also do not designate electrons to specific contracts, unless a contract says to do so. All of which is managed in ISO-New England Market Operations. So, generators sell into a market and load purchases from that clearing house market.

So, it's -- we use the term "system power", it used to be a common term in wholesale markets. "System power" is sort of like a cross-section of all the generation resources in the region.

So, could you, for example, when we produce our, I forget what it's called, but we annually provide to customers an insert in the bill that says the sources of the power we bought. And that's typically system power. It's a cross-section of all the generation in New England. So, there is renewable generation in there. I mean, we also buy specifically from Burgess and Lempster.

So, is it -- is renewable generation in the supply we buy? I guess I would say "yes". Is it double-counting RPS requirements? I would say "no". That that's a constructive regulatory regime that ignores whether the electrons we buy, where they come from.

I don't know, is that -- if that's helpful or not.

A (Menard) And I guess, in order to say whether you're double-counting or not, so, what's done with the RPS proceeds? Right? Are they going back to the generators that are bidding into the market that's, you know, creating the system power? Or, are they going to, you know, individual customers that aren't selling it into the market?

A (White) Yes. It's an additional revenue stream for those generators.

Q Right.

A (White) It is not part of energy market clearing prices at ISO-New England.

Q Yes. And I think I agree with that. You know, it's almost an implication that it is all conventional power sources, because we just determined from the previous math that the renewable power sources cost something like 36 percent more. So, it would be unlikely that a renewable power source was in the number. It would all be conventional numbers. Unless, Ms. Menard, to your point, if that 36 percent was going back into the renewable, like the wind generation or whatever, and when they made their quote into the -- into the supplier, that that was incorporated in their quote. Does that make sense? Is that what's happening?

A (White) I think so, if I follow you. And they don't do that, because they wouldn't win any business, --

Q Right.

A (White) -- because they're competing against generation that doesn't have that component.

Q Right.

A (White) That's it was done outside of those markets, to provide additional incentive and revenue to promote those types of generation.

Q Okay. Okay. Thank you. Very helpful. And then, my final question, Mr. White, is what happens to any unused portion of the power purchase?

A (White) There is no unused portion. They -- whatever loads, actual loads, turn out to be, that's what they're obligated to ISO-New England. The Market Administration does all that.

Q Okay. Okay. So, there is no unused portion, okay.

A (White) Right.

CHAIRMAN GOLDNER: Excellent. That's good news. All right. Thank you.

Mr. Fossum, any redirect?

MR. FOSSUM: I had one question, but Mr. White got to it. So, no thank you.

CHAIRMAN GOLDNER: Thank you. Then, we'll release the witnesses. Thank you very much.

So, without objection, we'll strike ID on Exhibits 3 and 4 and admit them as full exhibits. And we will hold the record open for the record request that Commissioner Chattopadhyay had earlier, relative to working capital/lead-lag study.

Okay. So, for closing arguments, OCA, Mr. Kreis?

MR. KREIS: Thank you, Mr. Chairman. Just very briefly.

As I suggested at the outset of the hearing, although we are living with the unwelcome effects of a uptick in wholesale natural gas markets and the resulting effect on wholesale electricity markets, such that customers in all classes are in the process of inuring themselves to significant increases in Default Service rates, the solicitation conducted by Eversource last week, as reported to you in the Company's filing, is what I would call a "nominal" solicitation, in the sense that it's obvious the Company complied with the rubric for conducting that solicitation as agreed to several years ago. The process and the results, although they yielded higher numbers, are typical of what a solicitation like that should generate.

And I believe that the evidence adduced at today's hearing gives the Commission ample basis to conclude that the resulting Default Service rates are just and reasonable, particularly with respect to the Residential class that whose interest the OCA represents.

I'd just like to make a couple of other observations based on some of the more general inquiries that I've heard today.

The first one is that I would caution the Commission to not necessarily conclude that either the public interest or applicable state law inevitably requires the Commission to set default service rates at whatever lowest possible rate the process could yield. And here's why: I think it goes to something I alluded to earlier, which has to do with the purpose and effect of the Restructuring Act. I think the New Hampshire Supreme Court misunderstood the Restructuring Act, to some degree, in the Algonquin Natural Gas case, by concluding that whatever results in lower rates is what the Legislature was asking the Commission to approve.

I actually think that the Restructuring Act has a lot to do with making sure that the risk of bad things happening financially is allocated to the right people. And, for the most part, the risks -- certain risks that used to be on the backs of the customers were transferred via the Restructuring Act to the backs of investors. But one thing that the competitive market was supposed to take care of is the actual prevailing price of electricity, as opposed to all the other things that electric customers pay for.

And, so, if we take the Default Energy Service rate, and make sure that that is as low as it possibly could be, it might have the effect of either placing too much risk on the backs of Default Energy Service customers, or it might inhibit migration to other suppliers, including community power aggregation suppliers, who might be in a better position than the utility to provide customers with the best possible deal that they might expect in this restructured world we have.

And then, you know, with regard to some of the other things that the Commission was asking about today, that have to do with the effect of the Renewable Portfolio Standard and the state of our electricity markets, and what would happen if we actually increased or decreased the amount of renewable energy that we require our utilities to procure on behalf of residential customers, as well as competitive suppliers, I get anxious and itchy, when hearings like this are used to illuminate issues that are outside the four corners of what the Commission is actually being asked to decide.

And I would respectfully suggest that what all of this seems to yield, in my mind, is a need for more informal workshops and more informal rulemaking proceedings before the Commission, so that these things can be aired and vetted in an -- in a context that's both more informal, but that is fair to everybody. Because, after all, there are parties who are not present here today who would have a very keen interest in helping the Commission answer some of questions that it's been posing today. And, so, I would urge the Commission to consider vehicles like that for addressing some of the questions that have been aired today, because they're important questions, and they deserve reexamination.

One question that I have been

suggesting for several years that the Commission reexamine is the general question of how best to have utilities procure default energy service. And, as one of the witnesses alluded to today, there's some possibility of having those solicitations occur on a statewide basis; that might be a good idea or it might not. I don't know what the answer is. But, again, I think an informal process would be the best way for the Commission to address those issues.

So, again, I believe that the Commission should approve, in a speedy fashion, the Default Energy Service rates that are proposed by Eversource here today.

Thank you.

CHAIRMAN GOLDNER: Thank you, Mr. Kreis. Mr. Wiesner.

MR. WIESNER: Yes. Thank you, Mr. Chairman.

The Department of Energy has reviewed the Company's filing in this proceeding, and determined that the Company conducted its wholesale power supply solicitation and selected winning bids to provide default energy service, in compliance with the Settlement Agreement and the process previously approved by the Commission in 2017.

I will just take this opportunity to echo some of the observations of the Consumer Advocate this morning. I do believe the Electric Restructuring Act provides a backdrop and context for the Company's procurement of default energy supply. However, the specific details of the requirements for the Company's procurement of that supply and development of Energy Service rates are set forth in the Settlement Agreement that was approved a few years ago in Docket 17-113.

All that said, the Department believes the Company's selection of the winning suppliers was reasonable. It was the result of a competitive procurement that reflected current wholesale power market conditions. Noting that the prices in that current wholesale power market are considerably higher than we saw last year and in other previous years, as the Company's testimony suggests.

We also believe the Company's

calculation of the rates, based on its supply bids and other factors, appears to be sound. As a result, we believe the Energy Service rates proposed are just and reasonable, and suggest that the justness and reasonableness of those rates is the primary criteria for approval.

I do want to note one point for the record and ask the Commission to take account of that point. We note that the Company's updated RPS revenue and expense schedule, and this is Bates Page 050 that we've discussed this morning in ELM-2, Page 4, which the Company provided for informational purposes, includes a revision based on the approximately $5.2 million error described by Ms. Menard in her testimony this morning. We believe that revision is questionable. And it might be seen as retroactive ratemaking were a future RPS reconciliation be proposed based on the change. However, because the change would not have an immediate impact on the RPS adder, we do not believe it needs to be litigated today.

However, we would ask the Commission to note the issue in its order and preserve it for a future challenge and adjudication, if and when that is appropriate.

Subject to that limited exception, the Department supports Eversource's filing and urges the Commission to grant the Petition, make the findings requested by the Company, and approve the proposed Energy Service rates in this proceeding for effect February 1st.

Thank you.

CHAIRMAN GOLDNER: Thank you, Mr. Wiesner. Mr. Fossum.

MR. FOSSUM: Thank you. I don't know that have just a whole lot to lay onto the record beyond that which the Consumer Advocate and the Department of Energy have already said.

Quite evidently, the Company believes that, and the witnesses have testified, that the solicitation that was done was consistent with the Settlement and order governing these solicitations. It was, as these things go, essentially regular and routine. That the calculation of the retail rates coming from that solicitation were proper and appropriate, and that they result in just and reasonable rates for customers.

I think we also certainly share some of the concerns as noted in the Consumer Advocate's observations. And it probably is appropriate to review some of those issues in greater depth, and the exact means by which I think we're open to discussing, but I likewise agree that they are not issues for this proceeding.

Beyond that, we have the pending record request, which we will endeavor to answer as quickly as possible, likely by tomorrow, so that this record can be complete and closed out, in time that the Commission might be able to issue an order approving these rates by this Thursday, December 16th.

And I will note, this is my opportunity to note my error in the Petition references the wrong date. And, so, I'm clarifying here that our requested order would be by this Thursday, the 16th.

So, with nothing further, we support the just and reasonable rates as calculated, and we ask that they be approved for effect on February 1st of 2022.

CHAIRMAN GOLDNER: Thank you. Well,

thank you, everyone. We'll take the matter under advisement, issue an order. And we are adjourned.

(Whereupon the hearing was adjourned at 11:25 a.m. Please note that following adjournment, after conferring with Chairman Goldner, the record request will be identified as reserved ***Exhibit 5****.)*