ORIGINAL

RE: DE 24-070

PUC HEARING

October 08, 2024

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STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

October 8, 2024, 9:01 a.m.
21 South Fruit Street, Ste. 10
Concord, New Hampshire

ORIGINAL

RE: DE 24-070
Public Service Company of New Hampshire
d/b/a Eversource Energy
Request for Change in Distribution Rates
(Prehearing Technical Session, Day 3)

PRESENT: Chairman Daniel C. Goldner, Presiding
Commissioner Pradip K. Chattopadhyay
Alex Speidel, Legal Advisor
Tracey Russo, Clerk

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APPEARANCES:

Reptg. Public Service Company of
New Hampshire d/b/a Eversource Energy:

Jessica A. Chiavara, Esq.
Jonathan A. Goldberg, Esq. (Keegan Werlin)

Reptg. Residential Ratepayers:

Donald M. Kreis, Esq., Consumer Advocate
Matthew Fossum, Asst. Consumer Advocate
Michael J. Crouse, Esq.

Reptg. New Hampshire Dept. of Energy:

Paul B. Dexter, Esq.
Alexandra Ladwig, Esq.
Molly Lynch, Esq.
Jay Dudley, Utility Analyst
Jacqueline Trottier, Utility Analyst

Reporter: Nancy J. Theroux, LCR, RPR #100
(RSA 310-A:161-181)

APPEARANCES: (Continued)

Reptg. AARP:

Christina FitzPatrick, NH Director
Patrick McDermott
John Coffman (remotely)

Reptg. Clean Energy New Hampshire:

Chris Skoglund, Director of Energy Transition

Reptg Conservation Law Foundation:

Nicholas Krakoff, Esq.

ALSO PRESENT:

PSNH, d/b/a Eversource Energy:
Lavelle Freeman
Doug Horton
Robert Coates
Ashley Botelho
Dominick Brescia
Brian Dickie
Paul Renaud
Sandra Gagnon
Warren Boutin
Mark Kolesar
Agustin Ros
Andrew Belden
Dr. Elli Ntakou
Dr. Gerhard Walker
Matt Cosgro

APPEARANCES: (Continued)

REMOTE PARTICIPANTS:

Marc Lemenager
Nicholas Crowley, Consultant
Donna Mullinax, Consultant
John Coffman, AARP
Adam Aguirre, CLF
Fatou Dieng
Jennifer Schilling
Shamus O'Brien
Steven Casey
James DiLuca

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P R O C E E D I N G

CHAIRMAN GOLDNER: Okay. Good morning. I'm Chairman Dan Goldner. I'm here today with Commissioner Pradip Chattopadhyay. This is day 3 of the Prehearing Technical Conference attended and presided over by the Commission regarding the Eversource performance-based ratemaking or PBR proposal presented to the Commission in its distribution rate case docketed in DE 24-070.

Today's technical conference conversation is focused on expected interplay between the Company's PBR proposal in general and the Distribution Solutions Plan concept also put forward by Eversource in its rate case filing.

This also includes solar installations that would be built and owned by Eversource, though it is not clear whether this would be accomplished under the statutory framework established under RSA Chapter 374-G.

We'll now take roll call, beginning with the Company, acknowledging that certain parties were not here last Thursday. Eversource.

MS. CHIAVARA: Yes. Good morning, Commission. Jessica Chiavara, here on behalf of Eversource Company of New Hampshire, doing business an Eversource Energy, and I have co-counsel here with me today, Jonathan Goldberg, Senior Counsel at Keegan Werlin.

CHAIRMAN GOLDNER: Very good.

AARP.

MR. COFFMAN: John Coffman here on behalf of AARP, New Hampshire.

CHAIRMAN GOLDNER: Okay. Thank you.

Alexander Cook. (No response.)

Clean Energy New Hampshire. (No response.)

The Community Power Coalition of New Hampshire. (No response.)

The Conservation Law Foundation.

MR. KRAKOFF: Good morning, Commissioners. Nick Krakoff for the Conservation Law Foundation.

CHAIRMAN GOLDNER: Thank you.

Rate LG Customer Consortium. (No response.)

Mary Ellen O'Brien Kramer. (No response.)

NECTA. (No response.)

The New Hampshire Department of Energy.

MR. DEXTER: Good morning, Mr. Chairman, Commissioner. Paul Dexter from the Department of Energy. I'm joined by Alexandra Ladwig and Molly Lynch from the Department's legal division and Jay Dudley and Jacqueline Trottier from the Department's regulatory division.

CHAIRMAN GOLDNER: Thank you.

The Office of the Consumer Advocate.

MR. CROUSE: Good morning, Commissioners.

In addition to my introduction, I just had two very brief observations that would be useful to the Commission.

My name is Michael Crouse, staff attorney for the OCA representing residential ratepayers. The first notice to the Commission is that the Consumer Advocate, due to a medical

appointment, will be joining us in 30 minutes.
The second notice is that last week, there were some microphone disturbances. I observed that the microphone to my left was making and picking up noise even when off, and thought I would let you know. Thank you.
CHAIRMAN GOLDNER: Okay. Thank you, Attorney Crouse.
Standard Power of America.
(No response.)
And, finally, Walmart. (No response.)
Okay. Are there any other persons or entities wishing to be acknowledged today?
MR. CROWLEY: If I may, I'm Nick Crowley with the Department of Energy. I'm a consultant to the Department of Energy.
CHAIRMAN GOLDNER: Okay. Thank you, Mr. Crowley.
Okay. Thank you. So we have a few follow-up questions from the last proceeding. Then I believe the Company is planning to make a presentation relative to DSP today?
MS. CHIAVARA: That's correct. Yes,

we have some slides prepared.

CHAIRMAN GOLDNER: Okay. Thank you. Can the Company file that presentation with the Clerk's Office?

MS. CHIAVARA: Absolutely.

CHAIRMAN GOLDNER: Okay. Thank you.

And I think you sent the initial PowerPoint presentation from the first PBR -- I'm sorry -- from the first PHC in already. Any concerns with posting that as well?

MS. CHIAVARA: No. That should be fine.

CHAIRMAN GOLDNER: Okay. Okay. So thank you. So after some initial questions -- pardon me -- from the Commission and the Company's presentation, we'll continue with Commissioner questioning regarding the interplay between the DSP and the Company's solar PB build-out and performance-based ratemaking. And I'll just ask if any the other participants here today plan to ask questions of the Company for planning purposes today.

MR. DEXTER: Thank you, Mr. Chairman.

The Department doesn't have any prepared questions, but would like the opportunity to ask some follow-up after hearing the presentations.

CHAIRMAN GOLDNER: Okay. Thank you. Attorney Crouse?

MR. CROUSE: The OCA has no prepared questions at this time. Thank you.

CHAIRMAN GOLDNER: Okay. Anyone else?

MR. KRAKOFF: Commissioners, I have no prepared questions, but I reserve the right to ask a few follow-up questions.

CHAIRMAN GOLDNER: Okay. Of course.

MS. CHIAVARA: And, Mr. Chairman?

CHAIRMAN GOLDNER: Uh-huh.

MS. CHIAVARA: We also prepared a few slides on the DSP, just an overview. It's nothing new, but it's just a -- sort of an executive summary of what we actually filed, and we thought it might be of assistance to get the conversation started off. We can present evidence, if you like, after we address last week's follow-up questions.

CHAIRMAN GOLDNER: Perfect. Yes, that

was the plan. Yes, exactly.

Okay. Just a moment.

(Conferring.)

CHAIRMAN GOLDNER: The only other item is that -- I'll just highlight -- that just as with the prior sessions, we'll take regular short breaks, a one-hour break at noon, and we plan to be completed by 4:30 -- no later than 4:00, I should say.

Okay. So let's begin. Let me just start with a couple of follow-up questions on the last session.

So I wanted to start with -- I appreciated Mr. Crowley and the DOE's questions on Thursday, and I'd like to follow up on that. And what the Commission would like to see from the Company is what I'll call the governing equation for the Company's revenue requirement. You provided a governing equation for PBR, though, I think we discovered last week, it was incomplete. And so in that governing equation would be everything in the revenue requirement, so what's inside PBR, what's outside PBR, the other factors, all in equation form, so that we, the Commission, and the other parties can understand exactly what your ask is for the revenue requirement.

Any concerns on that, Attorney Chiavara?

MS. CHIAVARA: No concerns. And I do believe we've prepared something to that effect for today.

CHAIRMAN GOLDNER: Okay. Great.

MS. CHIAVARA: I'm sorry. I believe we are still trying to get access to the screen to present, so I'm --

CHAIRMAN GOLDNER: Then, secondly, I also appreciated Mr. Dudley's question from last Thursday. And, admittedly, speaking only for myself, I still don't understand Mr. Horton's ROE analysis. And I know, Attorney Chiavara, you took a note on this, but I'd like to make sure the Company puts pen to paper on how this would work. You know, PBR's sort of foundational premise is that it encourages the Company to control expenses, so this is regarding foundational. And so I think it's best if the Commission understands exactly what the Company is putting forward and how PBR helps the Company control expenses.

And Mr. Horton made a reply to Mr. Dudley at the last session, and -- and so I'd just like to follow up on that and make sure -- the Commission, for sure, and the Department and the other parties also understood the Company's position.

Okay. The clerk's have just sent Attorney Chiavara another link, so if you can check your email, you should have another linkage.

And I'd also like to thank Attorney Krakoff for his questions. I have no follow-up on those questions, but the questions were helpful to us last week, Attorney Krakoff, so I thank you for that.

And I'll turn now to Commissioner Chattopadhyay to see if he has any follow-up questions from last week.

CMSR. CHATTOPADHYAY: I do not. Thank

you.

CHAIRMAN GOLDNER: Okay. And would the -- just making sure that we keep things moving, would the Company be able to file all these analyses and the other items that we asked for last week by 10/22, a couple of weeks? Would that be enough time?

MS. CHIAVARA: Yes, that should be fine. Subject to check, but yes.

CHAIRMAN GOLDNER: Okay. Thank you. And if you need longer, just file something, and that's probably not an issue. I'm just trying to keep the wheels rolling.

And at this point, assuming the Company is ready, we're ready to move on to the Company's presentation.

MS. CHIAVARA: The email just made it through Eversource's excellent firewall, so it took just a moment to get to us.

MS. BOTELHO: I'm not able to get on. It's not starting.

(Conferring.)

CHAIRMAN GOLDNER: Yeah, let's just

take a five-minute break and get the Company some time to sort of get things settled in without feeling hurried, and we'll just return in five minutes.

(Recess taken.)

CHAIRMAN GOLDNER: Okay. We'll go back on the record. And I'll move over to you, Attorney Chiavara and Eversource.

MS. CHIAVARA: Thank you, Mr. Chairman. I believe Ashley Botelho is going to start this presentation; is that correct?

MS. BOTELHO: We have Lavelle starting with the DSP.

(Conferring.)

MR. FREEMAN: Good morning, Commissioners. My name is Lavelle Freeman. I'm Director of Distribution System Planning. A pleasure to be before you once again.

I will take about 20 minutes to walk through 17 slides on the distrubution system in New Hampshire and our distribution planning methodology. I welcome questions as we go through. I think that will add to the tenor of the discussions.

And then after that, I will pass it to my colleague, Paul Renard, who will talk about the capital expenditure and the distribution system assessment. Next slide, please. Next slide.

So the distribution system in New Hampshire is really subdivided into five regions, which are aligned with our operational districts. The northern region stretches from Concord to Pittsburg. It's really the largest, by far, region. And it's really two electrical areas, if you think about it, is Concord to the White Mountains, and then White Mountains north, to the north.

And this region -- and I will talk about it as we get into some of the planning challenges, really presents as a region with really, really long feeders and, historically, lower reliability than seen in other portions of the state, which portends some the planning challenges and solutions for this region.

The central region is really the

greater Manchester area. It includes an area following I-89 up towards Hopkinton.

The eastern region comprises New Hampshire's seacoast, the Epping area and the tri-city region of Dover, Somersworth, and Rochester. And this is probably the fastest-growing region in our district. Some of the step loads are the largest loads that exist that we're seeing driving our planning solution in this region.

And the southern region is the greater Nashua area, including areas around Milford and Derry.

And, finally, the western region comprises the southwestern portion of the state, from Keene up to Newport due north.

And the western region and the northern region, particularly, are areas where we're seeing significant amount of DER growth, again leading to planning challenges.

As I go through planning, I will emphasize that we plan for load and we plan for DER using the same methods, the same tools.

They're two sides of the same coin, and so we ensure that our facilities can accommodate the load demand and the DER demands.

We -- the areas are further subdivided into 13 area work centers and two satellite centers, which support the regions with large territories, and, therefore, commensurate longer restoration times.

We have 123 substations across our territory. Fifty of these are bulk distribution substations. And I talk about these bulk substations ad nauseam because they really are the centerpiece of a lot of the planning that we do.

The graphic to the right shows the bulk distribution substations as blue circles distributed across our territory. It's important to note that the areas that tend to have more load, more commercial activity, are areas where there's a higher density of bulk distribution substations, not surprisingly. And the areas with lower load density, such as the north and the western regions, tend to have less bulk distribution substations.

The bulk distribution substations serve an area of the territory, and they're designed to serve the customers in that area. And so if you have long distances between bulk substations, you will have commensurately long distribution feeders. Long feeders tend to equal lower reliability. And that sets up some of the planning challenges that we're seeing and that we will discuss further.

Our system, at the distribution level, is predominantly 34.5 kV and 12.47 kV. 34.5 kV is the largest distribution voltage used in the U.S. And because we have the distribution backbone, most of the three-phase portion of the system, as 34.5 kV, we can run longer distribution feeders and ensure that when those lines get to the customer location, the voltage isn't lower than it should be. And so the voltage regulation is assured by having a higher voltage.

At higher voltage, we can also tie into more power. And so longer feeders carry more power longer distances with good voltage regulation.

The drawback, again, is reliability. Longer feeders, overhead, more exposure to trees, to weather, to animals, and so that's a challenge that we are constantly trying to address with our design and with our operations, to ensure that customers have good reliability, even with this system design.

The graphic below shows the distribution of 539,000 customer accounts across the voltage levels. Again, because it's customer accounts, it's not necessarily the number of customers -- number of residents that we serve. It's the accounts, commercial, residential, and industrial. And, importantly, it does not include the number of co-op customers or municipalities that we serve. Those are seen as one account. But, as you know, it's a number of customers who need the same reliability and resiliency.

Next slide, please, if there are no questions.

So these 539,000 residential, commercial, and industrial customers create approximately 1.8 gigawatt, 1800 megawatts of peak electrical demand. And this is the demand that we have to plan for.

But when we plan for demand, we're not planning for demand at the state level. It's 1.8 gigawatts at a state level, and as you drill down into regional levels, and drill down even further to substations, then you are revealing the constraints of systems for the demand that we're seeing in localized areas.

The 1.8 gigawatts is evenly distributed across the regions. As you can see in the load axis, peak load 223 megawatts, about 80 percent of the load is in the central, eastern, and southern areas. The lower loaded areas of the north and the west, because the load is lower, they tend to have smaller substations with smaller transformers, and, therefore, less hosting capacity for DER.

And then the DER is mostly in these areas. As you can see from the column -- the row that says "Online DER" as a percent of peak load, second to last row, the in-store DER right now is 64 percent of the load in the northern region and 40 percent of the load in the western region. And this begins to manifest as a problem when we have a low load period -- you know, a nice balmy day in April or May, when air conditioners are not running and it's a clear sky, and the DER is producing like gangbusters. This is when you begin to see reverse flow on these substations flowing through the distribution transformer, into the transmission system, and thermally loading the distribution transformer, just as forward load would. And so that's something we have to plan for.

And spinning forward, the last row shows that the DER that's in the queue, the ones that are waiting to be started and connected would load the northern and western regions to 129 percent and 139 percent of capacity.

CMSR. CHATTOPADHYAY: Just a follow-up question.

In a previous slide -- or when you

were describing the other slides, you said, you know, longer feeders, less reliability. Do you have a reliability standard that you -- what is your standard?

MR. FREEMAN: So we have a reliability planning methodology, and we have standards -- and my colleague, Dr. Elli Ntakou, she manages reliability and resiliency, so I'll ask her to chime in if I misspeak anyway.

But we do have a reliability standard in the way we design the system and upgrade the system for reliability and the feeders that we adjust for more reliability. And that standard allows us to look at the feeders that have the worst performing characteristics and adjust those feeders. And we do tend to comply with any targets that the state gives, as far as SAIDI and SAIFI, and we design our system to ensure that, at a circuit level, we are performing with respect to SAIDI, System Average Interruption Distribution Index, and SAIFI, System Average Interruption Frequency, and that's basically the duration and the frequency of outages. Our standards are predicated on those two indices.

CMSR. CHATTOPADHYAY: Okay.

MR. FREEMAN: Next slide, please.

So this slide really encapsulates the challenges that we face across all three states. And I apologize for the small font, and I'll try to illuminate some of the issues we are seeing in each of those regions.

In the northern region of New Hampshire, we have these long 34.5 kV feeders --

CHAIRMAN GOLDNER: Excuse me, Mr. Freeman.

I have an idea, Attorney Chiavara. Could you maybe send the presentations to the clerks' offices. Maybe others are having a hard time viewing it. I'm sort of having a hard time, and I might be closer than many. It might be good if the clerks can receive it and then send it out as -- so everyone can see it from their own PC.

I think we can proceed, but I think that could be helpful as we go through the day.

MR. FREEMAN: Yeah. And what also

might be helpful, Commissioner Goldner, is saying the Bates page, 02032. This figure is in the DSP. Everything I'm presenting is in the DSP, and if you have that up, we can --

CHAIRMAN GOLDNER: And that was actually a complaint that I wanted to register today. In a lot of the Company's filings -- at least in the ones that are presented today, the -- what you filed with the Commission was in black-and-white, so you can't -- the color coding, particularly on bar tables, are not readable. So I'm not sure how we should address that, if you have any ideas, but a black-and-white filing in a lot of the cases for the charts make them illegible.

CMSR. CHATTOPADHYAY: And then the Bates page, I can't see it from here.

CHAIRMAN GOLDNER: So I think we can move forward, but I think if we -- if we can send that over to the clerks, Attorney Chiavara, that would be very helpful.

MS. CHIAVARA: Yes.

MR. FREEMAN: So this is on Bates page

02032, and it presents the fact that there are several different challenges across our service territory. But in localized areas, these challenges are even -- even more pronounced.

In the northern region -- think back to the previous diagram, where we had the circles on the chart. There are maybe three or four substations in the northern region. There's -- I think there's substations in Berlin, Whitefield. These substations are far apart from each other, and the distribution territory that they each serve is tremendous. And so, by design, the distribution feeders emanating from these feeders are long. Typically, over ten miles long, as many as 35 -- 35 miles long for the backbone. And then the laterals that come off of that backbone also have tremendous length. It's not uncommon to see total distribution length of 70, 80 miles to a customer location. So that brings, in itself, challenges.

So the lack, the sparsity of substations, the sparsity of transmissions in these areas, leads to distribution challenges around reliability and resiliency that we're trying to address in northern regions for customers that may have historically been at a disadvantage, and so we need to ameliorate that.

Going clockwise, the western region, another region that tends to have long, 34.5 kV feeders due, again, to the sparsity of distribution substations, and, again, challenged by reliability. These two regions are also challenged by DER growth, because there's lots of available land. Developers are building projects in these areas. We have to connect these projects into substations that are historically small, lack of force and capacity.

And so we're dealing with challenges of reliability and DER integration, which, again, creates thermal constraints to our system. If they're not addressed, could cause a shortage of some to fail and affect all customers. And so we're dealing with that as a challenge in the north and the west.

Moving to the Manchester area. It's an urban/suburban region, with a high utilization of existing distribution capacity. And so we're seeing step loads -- and step load are large loads, such as commercial buildings, that may be 500 kilowatts, a megawatt and above. And so when these loads are applying for interconnection -- for interconnection, and they have to connect them to the system, they create constraints on already heavily utilized equipment.

And so our challenge is to maintain the reliability, the capacity of the system in these areas, while accommodating these loads which are so critical for the commercial activity in the state.

The Nashua area, it sees a steady development form of commercial and industrial properties into new commercial and residential. So we're seeing somewhat of an evolution in the way these buildings are being used and some intensification of the use, and, again, that's driving some of the upgrades that we're seeing.

And then, finally, the Portsmouth and seacoast region, in the fastest-growing region in the East, have seen population migration over the last couple of decades move up to the seacoast and into Portsmouth and Dover and the Rochester area. And we're seeing some of the -- the activity create congestion and saturation in areas.

For example, the Dover area, where we're building a substation because we are seeing constraints on the existing equipment, and we are taking a two-transformer substation and we are transforming -- upgrading it to 62.5, creating a ring bus on the transmission to ensure that the transmission line doesn't take the entire substation down, and putting -- and we're putting a double bus on the distribution side, all in an attempt to create a reliable substation to ensure that these critical loads remain served.

And, for example, Cutts Street substation transformer, based on our forecast, which I'll get to in a moment, Cutts Street will be 140 percent loaded by 2032. It will be over 100 percent way before that. And so that's a project that we see a need to upgrade the substation to accommodate fast-growing loads,

loads in the Portsmouth area.

So it's an example of when you look at the state and you begin to go down to subregions and down to substation territories, the constraints -- the violations become more pronounced, because -- I will say this a couple of times -- distribution is local.

When you begin to look at distribution planning activities, you have to look at a localized level, and you have to solve local problems. I can't solve a problem in Nashua by building capacity in Manchester. It needs to be a Nashua solution. And that, again, is one of the challenges that we face.

CHAIRMAN GOLDNER: If I can just jump in. You mentioned, I think, that most of the development, from a developer perspective, was from the western region; did I understand that --

MR. FREEMAN: Yes, sir. The western and the northern region.

CHAIRMAN GOLDNER: Western and northern. Is that helpful to the Company, or is that -- is that development in the right area to help your situation, or is that unhelpful?

MR. FREEMAN: It's a good question. We don't look at this as helpful or unhelpful, because it's -- it's customers trying to integrate DER, and it's our duty to enable that.

Now, it's not the ideal location, from a capacity standpoint, and so it means that those customers often may have to pay to upgrade a distribution line, or worse, to upgrade a distribution transformer for us to accommodate them.

CHAIRMAN GOLDNER: And can you walk us through that work? So you touched on it a little bit last week, but it would be helpful for the Commission to understand that process.

So if a solar developer puts solar right next to a substation, it's in the perfect spot, that's one thing. If they put it in a way that's more challenging for the Company to integrate, that's another.

Can you just walk us through the Company's process and how it deals with maybe those two scenarios?

MR. FREEMAN: Sure. So when we study the solar impact on the system, it's studied from two perspectives. It's studied on the impact on the distribution feeder, the lines that go from the substation that serves customers, and the impact on the distribution substation itself.

And, you're correct, if the DER is close to the distribution substation, there is not a heavy impact on the line, because it's right there. There may be an impact on the distribution transformer on those clear, balmy April middays that I mentioned, when there's high output and very low load, that will reverse flow, may load the transformer beyond its capacity, and then we may have to upgrade the transformer in anticipation of that. And so that's one challenge.

The challenge on the distribution line occurs when the DER is out long distance from the substation, maybe on the end of a very long line. And in that case, the system on -- is weak, and a weak system means that any fluctuation in voltage impacts everyone on that line.

So when the DER output is varying due to cloud cover, every customer on that line may see the voltage also fluctuate. So we need to design the system so that distribution customers are not impacted by the DER. And so we would study the voltage impacts and ensure that we are maybe re-conducting the line to a higher, larger conductor, such that there's no fluctuation. And we also ensure that the DER doesn't impact the capacitors and the regulators that are out there to regulate voltage.

CHAIRMAN GOLDNER: So what does that look like from a developer's point of view? I'm Developer A, and I'm putting it right next to Substation A. I pay X. I'm Developer B. I'm far, far away from the substation, and -- like, how does -- how does the Company deal with the cost difference of implementing those two systems? What's the analysis from a developer point of view when you're talking to them about how much it will cost them, the developer, to put their energy on the system?

MR. FREEMAN: Yeah. So we do what's

called a System Impact Study, an SIS. And the System Impact Study analyzes all of the issues I just mentioned, and others, to ensure that the performance of the distribution feeder is within our standards.

And then we identify what solutions are needed for each DER. So we study each one individually, almost sequential, right, on the cost-causation principle. Which mean that, if you caused a violation, then you need to fix it.

And so every DER is studied, and the cost to mitigate the issues caused by the DER are borne by the developer. So if the DER, at the substation, causes an overload of the transformer, that developer will pay the cost to replace the transformer.

If the DER at the end of the line causes overvoltage or voltage fluctuation, and we have to upgrade that entire line all the way down, that developer pays for the upgrade costs.

CHAIRMAN GOLDNER: That's very helpful. And is there -- would you happen to have now, or maybe later this morning if it's not immediately available, maybe a couple of examples? In the last couple of years, what's sort of the minimum cost to a developer and the Company and a maximum cost to a developer and the Company? It'd be helpful for the Commission to understand what we're talking about in terms of dollars.

MR. FREEMAN: Certainly. I will have that for you after the break.

CHAIRMAN GOLDNER: Thank you.

CMSR. CHATTOPADHYAY: Also, this is out of just simple curiosity. Why do you think it's that, you know, DERs are -- the requests are coming mostly from the north and the western regions?

MR. FREEMAN: Available land. It's available land and the ability to get those permitted by the municipalities.

CMSR. CHATTOPADHYAY: So you're talking about not just solar rooftop, you're talking about other kinds of PVs?

MR. FREEMAN: That's -- that's a great clarification.

So when I'm talking about System Impact Studies and impacts on the distributive feeder, I'm talking about the front-of-the-meter, ground-mounted DER.

The rooftop solar generally doesn't create issues for us. Those are quickly and easily connected. They only present themselves as an issue in the aggregate, when there's so much of them that we have to look at the voltage issues. And so, typically, we see those mainly connected in the east and the south and the central regions on the rooftops, but there are only so many of these that can be connected. The vast majority of the DER in the north and the west are these large solar farms that tend to create issues on the distribution system.

CHAIRMAN GOLDNER: Would you mind going back to that previous slide quickly?

So the -- you said that, because of the land availability, the west and the north is where most of the solar is going in place. And that -- it's hard to see from here. It looks like that alliance with the north and the west, so that's where you also need the energy; is that how to read that slide?

MR. FREEMAN: No. Actually, it's the opposite. So the energy is needed in the east, south, and central, right?

CHAIRMAN GOLDNER: Yeah. So -- perfect, so -- so it's not coming in the right zone.

And then the other thing I'll mention is that my recollection of the solar irradiation maps is that, in New Hampshire, the southeast corner of the state gets a reasonable -- or let's just say, it gets an amount of solar radiation that's greater than in the northwest part of the state.

MR. FREEMAN: Yes.

CHAIRMAN GOLDNER: And so the solar is going in, as a practical matter, far away from your substations, and in an area of lowest radiation, so it -- it seems like this is not -- what's your assessment of that? It seems like it's going in in the wrong places.

MR. FREEMAN: So we've seen that solar

radiancy is not the driver for location of the --

CHAIRMAN GOLDNER: And why is that?

MR. FREEMAN: For example, Massachusetts has more DER than most states across the union, and has relatively low irradiance and insulation compared to states in the south. And a lot of it is driven by -- just by policy. And developers will tend to react to policy and develop projects, and size the projects -- so if there's available land, even if you don't have irradiance, you can size the project such that you get the output that you need to make your business case, right? You can oversize the panels, and you can -- you can get more energy out of the system if you're located in certain areas.

And my -- Dr. -- my colleague, Dr. Walker, wants to chime in. But before he does, let me address the part that -- of your question that states, are they locating in the right areas to offset some of the load, right, which is an important planning question.

If we are not depending on the DER --

and I'll emphasize a little bit more. We are depending on the DER across the state to serve the load and to offset the capacity that we are providing for customers. And that's because we have no control over the DER. We have no operational control. They're owned by developers, and they can produce or not produce or play in the ISO market -- whatever they see fit, right?

And so we have to design the system with the kernel in mind that this power might not be there when it's needed. And we need to provide the capacity, and we need to account for the load that will be there when the DER doesn't show up. And so one of the guiding principles of planning is that we're planning for the gross load, not the net load.

If you back out the DER and back out all of the other things that tend to mask the load, let's plan for that. Because, at some point, that will show up. And when it shows up, things will break. So let's ensure that we're planning for that worst case.

So I'll let my colleague now chime in.

DR. WALKER: Mr. Freeman already covered most of it. I just wanted to answer to that point with the radiancy. The panels are one of the cheapest parts of that solar installation compared to the interconnection across the land, the permitting process. So just putting a little bit more panels to get the same output, typically, does not impact the finances of those projects, so that can be compensated just by more panels.

CHAIRMAN GOLDNER: So just -- just to help the Commission understand the proportion. If you are putting solar panel in Phoenix versus the North Country in New Hampshire, how much more area do you need?

DR. WALKER: That's a good question. I don't have a good answer for you. I can go get -- if you want actual numbers, give me 30 minutes. We can figure that out.

There's going to be a difference. But also note that solar panels do not get more efficient in hot temperatures. And so they do lose efficiency the warmer it gets. So I wouldn't be surprised if the difference isn't as astonishing as you would expect.

CHAIRMAN GOLDNER: Yeah, because if you just looked at the solar irradiation, you would expect maybe a 3X difference. And what you're suggesting is, because of the heat making the solar panels less efficient, maybe it's more like 2X or something like that. So it's not proportional for the solar irradiation.

DR. WALKER: Give me five minutes. I'll get you a number.

CHAIRMAN GOLDNER: Very good. And the area issue, I think, is one just of covering up land, right? So you'd have farmland. You'd have, you know, land that's being used for different purposes, and you're covering it with the solar panels. So the more area you take up, the less farmland and other sort of, you know, useful area that you have.

So that's, I think, the way that at least I think of it. If the Company thinks of it differently, I'm just trying to understand the

Company's point of view.

MR. FREEMAN: No, that is true. You know, there's -- there's a significant amount of area that needs to be covered to get to the energy -- the power that it needs for the solar output.

CHAIRMAN GOLDNER: And just while we're looking at the calculations, just so the Commission can have a rule of thumb to understand at a high level what's going on. If you're putting solar panels in the North Country or anywhere in New Hampshire, but let's just use the North Country because that sounds like that's a lot of what's happening, how much area do you need per megawatt?

DR. WALKER: That's -- that's highly dependent on some local factors, but I think a good gauge, and subject to check, it's somewhere between four and six acres a megawatt.

CHAIRMAN GOLDNER: Thank you.

All right. Thank you, Mr. Freeman. You can turn to the next slide.

I think, Dr. Walker, while Mr. --

DR. WALKER: I have a number for you.

CHAIRMAN GOLDNER: Okay.

DR. WALKER: So this is directly cited from the National Renewable Energy Laboratory. So they're -- they say that in Arizona, you can expect roughly 6 kilowatt hours per square meter a day. And in -- most of New Hampshire being roughly the same, about 4 kilowatt hours. So there's a factor of 1.5.

CHAIRMAN GOLDNER: Okay. So 50 percent more efficient than the other region, which is much less than you would expect from the solar irradiation maps.

DR. WALKER: Yes.

CHAIRMAN GOLDNER: Okay. That's very helpful.

And so just to kind of -- a direct comparison would be, if you wanted to put in a 5 megawatt wind turbine, which is, I think, the current standard size, if I recall, for land-based wind turbines, versus a solar, in the North Country, it would be -- you'd need roughly 25 acres in the North Country for a single 5 megawatt wind turbine. That would be apples to apples, I think. So I'm just trying to understand the differences between the different technologies.

Okay. Thank you.

CMSR. CHATTOPADHYAY: Just a quick follow-up?

MR. FREEMAN: Sure.

CMSR. CHATTOPADHYAY: When you're talking about North Country, most of the DERs, are they wind, or are you still talking solar?

MR. FREEMAN: Most of the DERs that are in the queue, it's overwhelmingly solar.

CMSR. CHATTOPADHYAY: Okay.

MR. FREEMAN: But there's a significant install of biomass, hydro, all the types of DER, wind, that's there. But it's over 90 percent solar, now, in the queue, and battery storage.

And just to emphasize a point that Commissioner Goldner made earlier about the location of these DER being in the north and the west; whereas, the load to be served is in other areas. That really signifies to us a need for infrastructure to move the DER, particularly transmission infrastructure. Because, as I mentioned, that reverse flow is going up into the transmission system, and if you don't have those transmission lines to move that DER now -- DER generation to the east and to the south and the central regions, then we're doing ourselves a disservice.

Other point to note, with regard to DER build-out, and, again, there's about 700 megawatts in the queue that's coming. But, as we look at our systems and the evolution of our systems, across all territories that we serve -- in Massachusetts, for example -- and I don't want to -- Massachusetts is an example, right? If we are -- we are seeing, because of the EV heat pumps electrification driving in those states, they will be switching to winter peaking around 2035. A winter peaking system, the DER is not going to help you to offset the load. You really need to build a system to accommodate that.

Currently, in New Hampshire, I think

the fuse is little -- is longer. But, at some point, we expect all of the systems to move towards winter peaking. So we need to really take a good look at the ability of DER to offset that demand onto that paradigm.

Switching now to the ten-year load forecast, which is on Bates page 02120 to 02121 of the DSP. At a statewide level, the load forecast looks uninteresting, right? That's the first -- the top right chart. It looks flat, maybe even looks declining in some areas. So full transparency, we have to start with that.

That's what it looks like at the state level, but even though the load may appear flat or negative at an aggregate level, as I said before and continue saying, at the localized levels, when you drill down into the system -- and distribution is all local -- you begin to expose some of the violations and the constraints that we have to deal with from a planning perspective.

At a regional level, even -- and that's the bottom left chart -- the step load additions show a great disparity. In the eastern region, there's a significant demand of step loads compared to the other regions.

And so step loads alone will drive almost 50 megawatts of increase, from 2024 to 2033. Fifty megawatts in the New Hampshire system, that's a significant amount. That's several substations' worth of load increase. And, again, drivers are the development of Portsmouth -- Portsmouth downtown in our district, for which we have a plan for a substation upgrade to address that.

We also -- we see EV, electrical vehicle demand, as the second larger step load driver. Looking at about 12 megawatts of residential charging, mostly in the east and the south.

And so these are some of the online factors driving load increase in these regions. From a step load perspective, it's important to note that when we look at step loads, we look at step loads that are certain, the ones that we have a load letter from the developer that say what they're building, how much, where. It's going to happen. There's a work order that's being written for that.

We're also tracking the step loads that are probable, that are possible, that may be out in the future. But we're not planning for those yet, because there's some uncertainty, and it would be irresponsible of us to begin to build infrastructure for load that's possible or probable.

And so we track that, and we look at our lead time, which I'll talk about in a little bit, to ensure that we are given -- we have enough time to develop the infrastructure if that step load becomes certain. And so when we look at this yellow chart for the eastern region, you see it goes up to about 32, 33 megawatts, and then it flattens after a couple of years. And that's because, beyond 2027, we don't have any certain step loads in the east. We know about things that might happen. We have some indications of what customers are doing, but they're not -- they haven't progressed to the point yet where we will include them in our forecast and plan for them.

But as time goes on, in a moving window fashion, we begin to look at those loads, and when they become certain, we plan for those. Okay.

CMSR. CHATTOPADHYAY: Can I quickly ask, for the eastern region, the step loads -- step loads of 2025 through 2027, what is it about?

DR. WALKER: I can get that information to you precisely, noting that this will be high-level information, because we can't really divulge individual customer projects.

CMSR. CHATTOPADHYAY: Understood.

DR. WALKER: But within -- before lunch break, we'll have for you what's behind that. Whether we're looking at industrial, biotech, anything commercial based, we can get that split.

CMSR. CHATTOPADHYAY: Thank you.

CHAIRMAN GOLDNER: And just, maybe an opportune time to ask this question. So if there's 700 megawatts in the queue and lots of energy coming onto the grid, why would the Company need any Company-owned solar?

MR. FREEMAN: So maybe this is a good time to switch to the next chart, because the next chart shows, really, the progression of solar.

And so this is the growth in solar over the last two decades, Commissioner. And you see that over the last two years, we have seen an exponential growth of solar. Other things to note is that it's mostly small solar. The red -- the blue bars are everything that's less than 100 kilowatts, so it's mostly rooftop solar installed by residential customers for their own purposes to offset their loads. Like, I have 12 kilowatts on my rooftop. It reduces my electric bill. Okay?

Then there's some large ground-mounted installations that we have to study. 500 megawatts, about, is installed and 731 megawatts in the queue. These projects, again, developer-owned projects, none of them are owned by the Company. All of them are installed by the developer to reduce energy cost to derive revenue somehow from market programs. And they're operated with that in mind. They're not operated to reduce constraints on the Company's equipment. They're not operated to reduce the load that the Company has seen in particular distribution substations. And because we have no operational control over these, we cannot use them as distribution assets. And so, in my planning, I will discount those, for the most part.

Now, if there's a Company-owned solar farm that's on the Company's operational control, we can dispatch that generation to -- to reduce loading on, let's say, a substation, and that becomes for us a non-wired alternative. We have heard the term. For us, that's the differentiation between a non-wired alternative and just solar and DER, whether we have operational control and whether we can dispatch it to resolve a need that we have that we would otherwise build infrastructure to solve.

CHAIRMAN GOLDNER: And how does that

work for solar? I don't -- so the sun is shining. You have available energy. You can, I suppose, dispatch it in certain parts of the day that would be helpful. Obviously, at night or what have you, then it wouldn't be so helpful. So how does it work for the Company? I guess, I don't understand, when you say it's dispatchable, in a solar array, how does that work? I don't understand.

DR. WALKER: I can go quickly, just piggyback on the topic of non-wired alternative. So, as Mr. Freeman has already mentioned, in order for us to use any DER, not just solar, but call it storage and what else you have on the system as a non-wired alternative, the Company would need to dispatch it.

For a standalone solar, like, that's hard to do, because solar just produces as it does when the sun shines. And there, of course, are certain curtailment options that we would use to avoid constraints on the peak day. But, in most cases, that would be paired with storage. So you would pair solar and storage and utilize those two in a combined fashion, as a non-wired alternative.

CHAIRMAN GOLDNER: Okay. And when we get to the part of the Company's presentation or discussion on Company-owned solar, it sounds like that typically comes with storage?

DR. WALKER: I'd have to defer --

MR. BELDEN: Pardon me. Andrew Belden, Vice President for Solar Programs for Eversource. Our team is responsible for the development activities of our solar projects, as well as operation and maintenance of the solar projects that we currently own in Massachusetts.

I think, to your question about Company-owned solar and the potential value of that compared to privately owned solar, a couple of factors, you know, weigh on our decision to move forward with a project, which to -- to be clear, we are not proposing specific projects as part of this docket. We would, you know, very much focus on developing a project and then coming to you with that project in a separate docket, very similar to how Unitil approached their project.

But in terms of the value that we can provide, a couple of things. With the Inflation Reduction Act, there are new tax incentives or new structures for tax incentives that will allow utilities to take advantage of several benefits that we could then provide to the ratepayers.

Also, the land that we own, much of that is adjacent to substations, which means we can develop projects at a lower cost, potentially, than private developers who may not be similarly situated.

And then, you know, finally, laws currently in New Hampshire put upper limits on the size of distributed solar owned by other entities. Whereas, we're, under RSA 374-G, provided the opportunity to build larger projects, which may be more cost effective than privately owned projects.

CHAIRMAN GOLDNER: 374-G caps the Company at 5 megawatts; is that right?

MR. BELDEN: That's correct.

CHAIRMAN GOLDNER: Maybe we can pause

here and have a brief solar discussion. So if -- if there's -- how does the work -- how does the 5 megawatt limit work? If you have some 40 acres east of the substation and you build 5 megawatts, and you have 70 acres north of the substation, are those two separate 5 megawatt arrays, or how does -- how do those rules work?

MR. BELDEN: So we had different -- the 374-G rules state per interconnection. So, ultimately, we would be limited by the interconnection process to one 5 megawatt project AC. But what we can also do is upsize the project, so the DC scale might be 7 megawatts; whereas, the AC might only be 5 megawatts.

CHAIRMAN GOLDNER: Does that mean you can only put one 5 megawatt station or 7 megawatt station per substation, or how -- when you say "interconnection," what are the limits on interconnection?

MR. BELDEN: Yeah, so it would be individual point of interconnection on the system. And I think -- not to get too far ahead of ourselves, but I think we consider a project an individual point of interconnection on a single parcel of land.

CHAIRMAN GOLDNER: Okay. Okay. So it's really -- per parcel up to 5 megawatts is kind of the way the Company thinks of it. Okay. That's very helpful. Very good.

CMSR. CHATTOPADHYAY: But -- but there is no -- there's no legal impediment to sort of going with two different projects and -- you know, that are in the same plot.

MR. BELDEN: I would have to really consult attorneys on that, but I think our current perspective on it is an individual project would be one point of interconnection on one parcel of land.

CMSR. CHATTOPADHYAY: Thank you.

CHAIRMAN GOLDNER: Mr. Freeman?

MR. FREEMAN: So let's spin forward two slides. So I will get into our planning methodology, and I'll try to speed this up. I don't know if we --

CHAIRMAN GOLDNER: Take your time.

MR. FREEMAN: You may be sorry you

said that.

So I'm going to start with a high-level view of the electric grid. And it's just -- the grid really has three components, we know: generation, transmission, and distribution. And utility scale generation is interconnection across almost -- is across all New England, really. These are high-voltage power lines, and all these lines are networked together to create pretty much -- pretty much a superhighway that moves electricity from the power plant to electric substations.

Most notably, this is really a different paradigm than the distribution system. If you have a power plant in one part of New England that is decommissioned or that fails to produce, power plants in other portions of the system can pick up the slack. They're fungible. They're replaceable. On the distribution system, it's all local. There's no such thing as fungible in distribution.

And so when we build capacity in a particular part of the system, it had better perform, because if it doesn't, then customers may be out of power. So that will color the way we look at infrastructure and the way we look at non-wired alternatives and the standard that we hold them to, that performance standard, because assets are not fungible.

The distribution system is the backbone of a reliable electric power system that serves -- that is the interface between transmission systems and our customers. And whenever our customers feel pain, to the extent that they do, it can be tied back, in most cases, to the distribution system and to the design and operation of the distribution system, which is why we put so much focus on planning for that, or at least I do, because that's my role.

Next slide, please.

And if the distribution system is the backbone of a reliable electric power system, then the bulk distribution substation is a critical element of the electric power distribution system. And, again, those are those circles on that second slide that I showed.

And these bulk substations have several components. The transmission lines coming in, typically, they're 115 kV. We do have a couple that are served at 345, but it's really an exception. Most of our substations have 115 kV lines as source. And then distribution lines go out at 34.5 mostly. And they transition out via what's called a getaway. There's an underground section that goes out on a fence and then it transitions to overhead.

The top of the feeder is serviced by the breaker, typically. And this breaker is the protection element for that feeder. Whenever anything happens on that feeder, such as a fault -- fault current flows, that breaker is the last resort to ensure that that full current is interrupted on the distribution feeder. It's a really critical part of the design.

The protection and control room is the brains of the substation, in terms of the protection and the devices that switch and operate the substation. That, again -- the step-down transformer is the workhorse of the distribution substation. And these are the elements that are typically thermally constrained with regard to flow, either in the forward direction for load or the reverse direction for DER.

So we're really focused on assuring that our distribution power transformers are sized appropriately for the demand that we will see over the next ten years, not just tomorrow, not just next year, but forecasting for the next ten years, and ensuring that they can serve the demand that we're projecting.

Next slide, please.

So a significant portion of our planned activities at the power station level are driven by the performance of the substation. It really sets the stage for performance at all levels, and our ability to upgrade these systems are really a function of the lead time. It's why we plan. If we had a magic wand that we could wave, presto, and a substation shows up tomorrow, I would be out of a job. We wouldn't need a planner, right? But we need a planner, because it takes time to put that action into service. On the transmission level, it takes about ten-plus years to build transmission. Bulk substations, five-plus years. Again, that's the workhorse, so you're looking five years into the future to understand the needs for those.

Even primary feeders, either the 12 kV or the 34 kV level, it takes two to four years to build that primary feeder. And the lateral, which are typically single phase off of that backbone, you would think, quick? No, one to three years. Everything takes time. Even secondaries and services. On the secondary side of the service transformer that goes to customers' premises, it takes a couple of months up to a year to get those into service.

So effective planning are cause for this lead time to deploy transmission distribution assets in developing reasonable alternatives. And I would add, in developing reasonable alternatives in an orderly manner. And that's the key. Because if it's not orderly, if you're reacting, if it's chaos, it's expensive. Chaos is expensive, right? Orderly can be efficient. And so that's what we're trying to do when we -- when we develop our substations.

And I'll -- I'll talk a little bit later about what some of the performance requirements are, but -- so let's keep this in mind and go to the next slide.

Oh, distribution planning process, this orderly process that we're trying to -- to substantiate really is a cyclical process that happens every year. It starts with forecasting the net load on the system. It's a very important activity that my colleague, Dr. Walker, is in charge of.

That forecasting starts after the summer peak load, right? When the summer peak load has happened, the engineers and planning get together, and we begin to develop the peak system load for that year, accounting for a number of things. We may have had to transfer load from one feeder to the other, and that we have to back out and account for. We have to account for DER that maybe masks a portion of the load. It happened to be generating at the time, but what if it wasn't? And that's a what-if question you have to ask. What if it wasn't there, what would the load have been? Because next year, it may not be there.

And so we look at that. We look at the impact of electric vehicles, impact of electric efficiency, and we develop that peak load at every single bulk substation, so it's really granular.

And then that is given to Dr. Walker's team, and then the forecasting people, and they develop the long-range forecast over ten years at every single bulk substation. So what the planners get back from them is, for every year for the next ten years, what is the load expected to be -- what is the gross load expected to be, weather adjusted, at every single bulk substation.

And with that now, I can begin to use my tools, and I can do analyses. And I can impose that load on every substation, and I impose that load on every feeder, and then I run the analyses to figure out when a thing is going to break, how badly is it going to break, and when.

And now that tells me what solutions I need to develop and where these solutions would have to be developed. And this is a cycle that we -- you know, so, typically, in the first quarter, second quarter, we run these analyses and we develop the future capacity needs; develop cost-effective solutions probably in the second to third quarter. These solutions take it through our internal approval processes to understand which ones have the most merit. And I have a slide that will kind of illustrate that.

But this cyclic process is what really drives the planning every year for our power distribution substations. The overall guiding principle, I'll just read that, "is to enable disciplined, cost-effective build-out and reinforcement and replacement of equipment and facilities to meet future demand with acceptable system performance."

And what is acceptable system performance, you ask? Well, that's a good question. So I will -- I'll answer that in a slide or two, but just keep that in mind. Next slide.

CHAIRMAN GOLDNER: And this is something that the Company executives review annually, you said?

MR. FREEMAN: So, annually, when we develop the solutions, all these solutions are taken to what's called our Solution Design Committee. And this committee has directors and managers across the entire state, and they look at the solutions. And we typically bring, not just a solution, but alternatives. One of these alternatives includes a non-wired alternative solution, if it's doable.

And they look at these solutions, and they would decide which one has the highest benefit for customers, which ones should be -- should move forward, and which ones may have some opportunity to, for lack of a better word, co-optimize with some other solution.

There are many other needs across the system besides capacity, and there may be asset condition needs, and so we look for opportunities to do conjunctional projects to reduce costs for our customers.

CHAIRMAN GOLDNER: And what's the process for determining the best -- you mentioned that there's -- there's multiple options presented to the committee. What's -- what is their process? What are they considering when they decide which one is ultimately chosen?

MR. FREEMAN: So there are a couple of things that are not negotiable. So each project must meet the system need, right? And once --

CHAIRMAN GOLDNER: You wouldn't present that anyway, if it didn't, right? So that doesn't come in front of the --

MR. FREEMAN: It doesn't come in front of the committee.

And then we present the cost. That's a critical element. And most of the cost is developed at a -- at a conceptual level. All right?

And we look at the impact of the solution in terms of reliability. And there's a matrix that system engineers simply put together for consideration. We look at pattern losses. We look at environmental impacts; would one solution have an environmental advantage over the other. And there are a number of other -- other attributes that we look at for each project, and then each project is -- is ranked via these attributes, and a score is developed.

And this is presented as one piece of evidence before the committee, who will consider other things in their review of the solutions, such as, the ability to site the solutions and things like that.

CHAIRMAN GOLDNER: So, ultimately, one solution is chosen by the committee. It's built. And then it comes before the Commission in a rate proceeding, at some point, for prudence review; is that fundamentally how the process works?

MR. FREEMAN: I will defer to my colleague, but, to my understanding, that is how the process works.

MR. COATES: Yes, with one caveat. In that process, from the Solution Design Committee, it then becomes a project -- gets -- goes through a project authorization process. The executives are reviewing and signing off on those processes, and the outcome of the Solution Design Committee is reviewed and understood.

And, as Mr. Freeman highlighted, we look for those opportunities where we can solve two problems with one solution. Maybe we're solving Problem A for the capacity issue by also working on an asset condition on that line, etcetera. So we optimize the solutions. It goes to executive review, and then they would be executed and ultimately in the hands of the Commission for prudency review.

CHAIRMAN GOLDNER: Thank you. That's very helpful.

And my only follow-up, do the parties ultimately, in the rate case, have visibility into the options that were considered and what was ultimately chosen and the thought process, or do they really get the final answer, and then that final answer is subject to the prudence review?

MR. COATES: The project authorization form captures all the solutions, the reason and justification for the decision to build Project X, Y, or Z.

CHAIRMAN GOLDNER: Okay. That's -- I do remember that. Thank you. Thank you.

Mr. Freeman.

MR. FREEMAN: So the tools and methods that we use for performance evaluation are shown here. It just, my own point of showing this, is that's it's complex.

There are a number of methodologies and tools that we use across different time scales and different levels of granularity. For example, the steady-state thermal impacts. And a steady state is when there are no forces on the system, and the system is in equilibrium and operating continuous.

And for that, we typically use tools like Synergi. We used to use DistriView in New Hampshire. On the transmission side, we use

TSSC. And we analyze the system to understand the impact of forward and reverse flow on the distribution transformers on line equipment, overhead and underground distribution feeders and whether they're exceeding their thermal limits and their standards that we have both on the trans -- the substation and the distribution line side that dictate what is exceeding a thermal limit; what does that mean?

CHAIRMAN GOLDNER: Are those like IEEE limits, or are those Company-imposed limits?

MR. FREEMAN: Those are Company-imposed limits. They're Company standards. But they -- for things like voltage, they are in line with IEEE standards and some of those criteria.

CMSR. CHATTOPADHYAY: Can you tell me what the Bates page is?

MR. FREEMAN: Oh, sorry. It's 02090. I meant to say that.

CMSR. CHATTOPADHYAY: Thank you.

MR. FREEMAN: You're welcome.

Steady-state voltage impact, this is,

again, a result of load flow. We look at distribution feeder violations, and again -- I think in New Hampshire, it's plus/minus 5 percent of nominal. So, typically, on the distribution, we're looking for 114 to 126 volts at the customer location. And if -- if we see that we are violating that range, then we would plan something to mitigate that. And that is affected by the load during those peak times and affected by DER during light load times in the reverse.

DER will cause overvoltage, which can cause equipment issues, and load could cause under-voltage, which, again, creates equipment issues. And these are not as discernible as they used to be, now that we don't use incandescent bulbs anywhere, because you would see the dimming of bulbs yourself. But now we see effects on equipment, fans, compressors; any kind of thing that has a motor could be affected by low voltage. So we take a good, hard look at that.

We look at short-circuit impacts. When a fault occurs, how much fault current is flowing from the substation down the line, and ensure that the equipment is sized to handle a fault current, so it doesn't fail catastrophically when it sees this amount of current flowing, but also that flow current is very important for us from a protection standpoint. Because the fault current needs to be sufficient to allow the protection equipment to see it and to trip it offline. Because if you don't see it, then it stays there and creates a whole other problem.

So the systems are designed to ensure that there is sufficient fault current so that our protection systems work well, and so we can take equipment out of service quickly that has been faulted.

We do dynamic and transient analyses to understand the state of the system during a fault. When a fault has occurred, you typically get high transient voltages, as much as 1.7 per unit, 1.7 times the normal voltage, which, again, can damage equipment.

So we analyze the system to understand what is the risk of transient voltages and how to design the system so that you don't get that. And that typically happens with DER. When you have a lot of DER on the line and you open the breaker, the trap charge creates a lower voltage. And that's an analysis that we conduct for every single system in the study, to ensure that they're not creating transient overvoltage and that you're not incurring a risk of islanding, which means you have DER on the feeder, you open the feeder breaker, and the load at the DER is matched, so that the island sustains itself, and the DER continues to serve the load, in an unintended fashion. Because we don't want that to happen if we open the breaker. So we ensure that any DER that's in an island will trip offline in two seconds, and that island would die, basically, and customers would be out of power, which is what is intended if you open the breaker.

So, again, for every DER, we conduct that study, because it's a safety issue, and that's paramount that we do that.

And then we look at the reliability

and resiliency impacts. And this is becoming a larger part of our studies, doing databased reliability and resiliency analysis to understand the impact of past storms, how those storms have resulted in customer interruption and customer minutes of interruptions, and then designing measures down to the zone level to mitigate those impacts. And then -- and then -- and those solutions become part of our plan. And in the DSP, we included a resiliency plan that was based on that analysis.

CMSR. CHATTOPADHYAY: Just correcting, I think, Bates pages 02083.

MR. FREEMAN: Okay. I'll make a note of that. Thank you, sir. Okay. We'll correct that.

Next slide, please.

So with these advance tools and processes and methodologies that we use, the objective is to --

MR. DEXTER: Commissioner, I hate to interrupt, but following up on Commissioner Chattopadhyay, I'm having a hard time following the Bates page numbers. So if the speaker could announce the Bates page number when he says, "next slide," that would be helpful. I can sort of see them, but I'm having a hard time keeping up.

MR. FREEMAN: This was Bates page 91 -- 09 --

DR. WALKER: '2091 --

MR. FREEMAN: -- to '2093.

DR. WALKER: Yeah, to '2093.

MR. DEXTER: So that's not showing up on my 02091, '2, or '3. Well, I guess it is. On that chart with the red and the blue is showing up on 02093.

MR. FREEMAN: '93, and the text is on 02091.

MR. DEXTER: Thank you.

CHAIRMAN GOLDNER: Thank you, Attorney Dexter. Let's do this. Let's take a brief break. Attorney Chiavara, our clerks don't have the presentation yet, so if you could make sure that we take care of that on a break, and that way, that will solve a lot of problems in terms of identifying the Bates number and so forth.

But let's just take a brief 15-minute break, returning at a quarter of. Thank you. Off the record.

(Recess taken.)

CHAIRMAN GOLDNER: Back on the record now, and we can start with the Company.

MR. FREEMAN: So my colleague, Dr. Walker, actually has one of the data points you asked for, Commissioner, so --

CHAIRMAN GOLDNER: Thank you.

DR. WALKER: All right. So the question was on the step loads and what the makeup is. So very roughly, in four categories, we have commercial, industrial, residential, and transportation related, so EV charging.

The commercial makes up about 84 percent of all projects and 62 percent of the load. Industrial makes up 5 percent of the projects and 26 percent of the load. Residential, 5 percent of the projects and 2 percent of the step loads. And transportation, 7 percent of the projects and 10 percent of the load.

I hope that answers the question.

CHAIRMAN GOLDNER: Thank you.

CMSR. CHATTOPADHYAY: Thank you.

MR. FREEMAN: And we're -- everything -- we're getting the information from the DER costs. I will have that for you probably after lunch.

CHAIRMAN GOLDNER: Thank you.

MR. FREEMAN: So I have three more slides, and I apologize, I think I was going a little bit fast earlier. So I will slow down a little bit, because this actually is the key slide. Everything I have said before leads up to that slide. And I wish it -- I had put a pin in performance criteria, and so now I'm going to expand a little bit on that.

Our planning objectives with regard to the system performance are we provide adequate reliability and resiliency to disrupted events. And the way we do this is, as I said, by doing detailed analysis at every distribution feeder to understand two things: the frequency of interruptions for customers and duration of interruptions for each customer.

With those data points for each customer, we can build that up into any kind of indices or index in the industry. And you have heard the term SAIDI, SAIFI, CAIDI. That's where that comes from. And for most jurisdictions, reliability is about 99.98 percent, and that transmits to about two hours of interruption out per year. That would -- that would probably be second quartile, IEEE performance.

We assess our system to understand how we line up against those benchmarks and how we deliver, you know, reliability to our customers and commensurate with the system design. As I have mentioned before, there are certain realities with respect to how the system is designed and with respect to the exposure of long lines. That means we are going to have issues.

And the way we address that is by maintaining the system, by building in distribution automation to be able to reconfigure the system as much as we can, and by having operational response to ensure that we can dispatch those to repair and restore customers once they're faulted.

All of this constitutes a response and the ability to provide reliability and resiliency during disrupted events. But, again, it starts with planning the system and designing the system to assure all those other elements can help us to be responsive

We ensure that there's sufficient capacity to meet future demands and service needs, and the capacity constraints are exposed when we do analysis with the future load forecasts and understand what the constraints are. And the capacity applies from the distribution substation down to the lines.

At the transformer level, we ensure that during normal operation, our transformers are not loaded beyond a certain point. In New Hampshire, we ensure that 95 percent of the transformer capacity is used before we begin to trigger replacement. Okay?

So we're pushing all transformers and

the utilization of the transformers as much as we can. And just so you know, Commissioners, that's beyond what other states are doing. It's 75 percent in Massachusetts and Connecticut. We also ensure that on N minus 1, when the failure of transformer occurs, that the remaining transformer -- if there are two transformer substations -- has sufficient capacity to pick that up without being loaded beyond its long-term emergency rating for more than a cycle.

And so if it's -- we need to ensure there's ability to transfer load to adjacent substations via the distribution feeders to bring that transformer below its long-term emergency rating. These ensure that these assets stay viable, that they don't fail catastrophically, and that we get the performance and the longevity out of them commensurate with their design.

We also look at the distribution line and ensure that the distribution overhead as well as the conductors are not loaded beyond 80 percent -- if it's underground, 90 percent -- subject to check, if it's overhead. I will check on that. And those criteria are put in place to ensure -- actually -- is it 90? Okay. So I did check.

So those criteria are put in place to ensure that we have operational flexibility, that if it -- if there's a failure on the distribution feeder, we have sufficient capacity on other feeders to pick up load. A big part of load reliability and capacity assurance is the ability to transfer load to other feeders.

And so we have standards of criteria in place to ensure that we are not overloading ourselves, but also to ensure that there's sufficient capacity -- sufficient head room in the assets to ensure reliability. If we run all of our assets to the brink, if we -- if we load everything up to 100 percent, when something fails, customers are going to lose power, because we have no ability -- we have no operational flexibility. So we design our system to ensure that we can make moves to keep customers energized.

We also ensure that we satisfy all

voltage and power quality requirements within an acceptable limit. I want to mention the ANSI C84.1 standard, plus/minus 5 percent of the nominal. We also look at the flicker that may be imposed by DER, and ensure that that flicker does not impact our customers.

And we would put capacitor banks, voltage regulators out there. We put conductor feeders to ensure that the voltage that customers are seeing is compliant with the standards that we expect to have. And then we ensure that we serve all customers safely, wherever they exist. And that is -- that is paramount.

There is another element to performance, which is frequency. But frequency is more upgrading a bulk power transmission generation issue. The distribution system is typically not configured to resolve frequency issues.

The data analytics of tools that we leverage involve traditional/nontraditional sources. We have made a concerted effort to become a data-driven company. We have -- we are

-- within planning, we have hired data scientists, and we have built an advance planning group that looks at how we can leverage data sources to inform our planning decisions, sources such as solar irradiance scanners, understanding where solar irradiance is, understanding the ability of the DER to produce output from the flow and radiance information, and then being able to account for that in our planning.

Using EV mobility data, looking at vehicles and their travel patterns, maybe we have -- you see travel patterns of vehicles coming in from Massachusetts into ski resorts, and if Massachusetts is electrifying, you bet EVs are coming over.

And so we need to get ahead of the curve and understand that these batteries on wheels are going to be moving around and plugging in and maybe creating constraints on our service transformers, our distribution lines, and potentially our substation transformers, and get ahead of that and begin to plan for that proactively with regard to lead time. And so we use data to understand travel patterns and see how those potential EVs could be disruptive to our infrastructure.

We use GIS. We use parcel data to understand the ability to develop DER. Where is the developer land, and if that land is developed, what does that impose on the substation?

And so when we forecast solar, it's based on the developer plan, and we have databases that account for land that may not be developed over where they -- you know, whether it's park land, protected land, wetlands. But the land that is developable, we forecast the ability of DER to go into those areas and account for that in our planning.

So we're really trying to -- to do things from a data-centric and a defensible way, so that when we make plans, we are developing the right-sized solutions for the problems, and we're putting the state in the best position possible from a commercial development perspective as well as from a reliability and resiliency perspective.

So taking a long-term view of the system, when we develop solutions, we do it in a structured manner. We start by looking at the least-cost solutions first, and these would be, for example, reconfiguring the system to balance load. If you have a line that's overloaded, can we move some of those customers to an adjacent feeder and reduce the loading? That's a relatively low-cost solution, partially phased out in time. It's basically opening one tie and just closing another. That costs us nothing. And in the worst case, we may have to do some distribution feeder upgrades. But that's where it starts.

And then if that doesn't work, then we look at replacing or upgrading the limiting equipment, but only replacing and upgrading the equipment that is impacted by the constraint. Unless there is some other need. As Mr. Coates said, we try to aggregate and do conjunctional projects where it makes sense to resolve other needs. And so if a wider reconductoring technology is needed to resolve something else, then we would do that. But we tend to try to replace only the limiting equipment and constrain to our own system to what's needed.

We would add new equipment or expand the system capacity, so this could be expanding the substation. You could add a new transformer, add new lines, new feeders, add new capacitors, voltage regulators, whatever it takes to resolve capacity.

We construct or apply non-wired solutions where it makes sense, and we've discussed this. And there are some solutions that are not -- there's some needs, sorry, that are not suitable for non-wired alternatives, and those are possible needs that -- where equipment is aging, where this is a safety-related issue, an asset condition issue, we would tend not to suggest a non-wired alternative for that need. But certainly, wherever it's suitable, for capacity needs, for reliability needs, the planning engineers would develop a non-wired solution. And we have a tool that we've developed, NWA screening tool, that looks at the non-wired solution and compares it to the traditional solution, and does a benefit/cost analysis to ensure that the benefit of the non-wired solution outweighs the cost of the deferral of the traditional solution.

CMSR. CHATTOPADHYAY: Question.

Has Eversource -- regardless of where it is, New Hampshire, Massachusetts or Connecticut, have you constructed or applied non-wired alternative solutions already?

MR. FREEMAN: We have. In Massachusetts, we constructed a battery, a 21-megawatt -- 21-megawatt battery in Provincetown, Massachusetts, to resolve a reliability issue.

Customers on the end of a long line would typically see outages, if that line were interrupted, and so this battery was developed to mitigate that situation, and --

CMSR. CHATTOPADHYAY: That's the only one?

MR. FREEMAN: As far as I know, that's the only one. However, we're in the process of developing a couple others, and they're in the internal project development stage right now. One in Hyde Park. It will be a battery solution to relieve a station that is currently overloaded. Another one in an industrial park, which would resolve power quality issues. So those are two that are filed in our electric modernization plan in Massachusetts, and the information is there if you care to look at a 700-page document.

And we are also developing -- so we have proposed several in Connecticut with PURA, and right now, they're under consideration. And those battery projects, again, are to relieve substations that are projected to be overloaded. Instead of upgrading the transformer, this battery would allow us to push that project off several years and create value for our customers.

DR. WALKER: I just wanted to mention the Connecticut one as well.

MR. FREEMAN: Yeah. So one that's -- that has been completed, and it's in service. It has functioned as it was designed to function several times during events. And at least four that are in development.

CMSR. CHATTOPADHYAY: Thank you.

MR. FREEMAN: You're welcome.

And, you know, when -- when it's -- when we see the need, we'll build a new substation. And, again, there's a lot of analysis behind that, and whether we do it or not is subject to lots of internal checks. But that is a solution in our portfolio, to build a new substation. And oftentimes that is the right thing to do. And if it's the right thing to do, it's something that -- that I would be comfortable in advocating for.

The solution selection is a complex iterative process involving several groups in the Company to selectively find a solution in compliance with internal and external stakeholder requirements.

I discussed this a little bit before, but this -- Bates page 02091 to 02093 includes a discussion and this diagram, which I admit is a little bit small here, but scanning from the left to right, the first block says the need is identified.

And so for a typical capacity project, a reliability project, that would be system planning. For a line project, it could be distribution engineering. For an asset condition project, it could be asset management. But the need is identified, and then initial funding is procured for the engineers to do analyses to scope out the need and to develop conceptual solutions, which are then taken to the engineering team to develop conceptual grade estimates and to do preliminary engineering.

This solution is presented to the Solutions Design Committee, if it's a substation or transmission project. If it's a distribution line project, it's presented to the New Hampshire Project Approval Committee, the New Hampshire PAC. And each of these committees, again, has representation from all across the Company to examine the case for need and to ensure that the right solution is selected.

And then the full -- we go to what's

called Eversource Project Approval Committee, the PAC. That's another committee that decides on the funding. And once a project is funded, then it goes into construction. And as I said earlier, there's a prudency review that occurs with -- with the PUC. So I will pause there.

My next two slides are on forecasting. I just want to make sure that I get any planning questions out of the way first.

CHAIRMAN GOLDNER: I think we're good for the next slide.

MR. FREEMAN: All right. So I will let Dr. Walker present the next slide. I could present them, but he would do them more justice than I can.

DR. WALKER: I think Mr. Freeman already talked a lot about some of these components. I repeat just as a quick overview of how the process works.

Can everybody hear me? We get closer, it works better.

So there's two -- two components to how the forecasts are built. Number one, Mr. Freeman already said, we review annually our system peaks. So the first thing that happens in the review of the system peak is that we record net station load. So this is station load as it is at time of peak at the station, but that includes a lot of things. It includes distributed generation that's offsetting some of the load that can switch transfers at that station at the time, which might increase the load or decrease it under a normal -- normal operating conditions.

So engineering reviews all of that and corrects that. And just, FYI, for those who are looking at the Bates page, that's 02107. Sorry. I forgot that at the beginning.

So that gets corrected. We back in generation, and then we do a 90/10 weather adjustment. So that weather adjustment is important. It was last summer -- not this summer, but last summer was relatively mild, so station peaks recorded at the station will come in lower, and might lead to the wrong conclusion that peaks are coming down. So corrections are made to a standard weather model, and we correct those values up to what the 90/10 weather expectation is. So that leaves us with a gross station peak, a 90/10 gross station peak.

Next slide, please.

MR. FREEMAN: And just, for example, on this slide, I -- there's a Bridgewater Power Plant. That's a 16.5 megawatt plant. It's a biomass plant that exports power. We would take that plant and back it out, because we don't operate that plant. Similar for the Leominster 24 megawatt wind turbine, and the Amoskeag 16 megawatt hydro plant. Those are three examples that this team would look at the output, how much that output is masking load, and back it out. So that when we build capacity, if during a three-day heat wave that generation isn't running, we are not on that size and equipment. We want to make sure that we will see the right load at the right time.

DR. WALKER: Yeah.

So at this point, we basically have a weather normalized gross load, 90/10. So now this is where the forecasting begins.

So a couple of things happen. We build an economic model that looks out five years to -- five to ten years to develop the trend load, and then we have what's called out-of-model adjustments. So energy efficiency programs would be an out-of-model adjustment. Those get subtracted from the projected load. DER forecast gets projected, so it's the same thing on the solar side. That's both for the existing DGs that might offset the peak and anything that is forecasted to offset the peak.

When we do those models, we do look at time of day for the peak. So if it's 6:00 o'clock in the evening, the solar tends to have less output at 6:00 o'clock, so that's adjusted. So any numbers you see in the filing are representative of the impact to peak, not the installed capacity. Just make that distinction. And then any changes on the system, such as permanent load transfers, are taken into consideration.

Now, on the -- on the additions. We

have already talked about the step loads in great detail, so those are out-of-model adjustments, where we have certain customer loads coming into the system. Those are added in at the right locations.

Another item, as we're starting to see this, step by step, and Mr. Freeman already spoke about it, is EV charging. Now, for the 10-year forecast, the EV charging component is the light-duty vehicle component, so this is your at-home residential charging, opportunity charging, et cetera.

Larger charging installations, like fleet depots at the side of the interstate, you name it, those come up under the step loads. These are very locational. Those are very high impact at that location, and, typically, more than the 500 kilowatts, so we don't forecast those. We work directly with the developers to understand where they want to develop those so we have precise locations because of the size of the impact.

So that's the distinction here between

what goes into the forecast. That's the light duty, that's a spread-out charging, and then the very localized fleet depots charging infrastructure that comes in through the step load tracker. And that then gives us our forecast. That's the high level of how this is done.

Any questions on those two slides before we go on?

CHAIRMAN GOLDNER: I think I just -- I didn't quite fully grasp the base assumption on the 90/10. Just, can you explain that a little? I'm not sure that's terminology I'm familiar with.

DR. WALKER: Yeah, so what 90/10 essentially means is that we look at the -- let me rephrase this. It's the one out of ten-year worst-case scenario that we're looking at.

CHAIRMAN GOLDNER: Okay.

DR. WALKER: So if we review the peaks from the last ten years and the corresponding weather at that time, the weather we look at is a three-day weighted average Temperature-Humidity

Index. It's a very long term. But, essentially, what's underpinning this is the statement that, if you have just one hot day, that typically doesn't do much to the load. Buildings are still cool. Air conditioners don't need to do that much. But if you have three hot days consecutively, your load tends to keep creeping up. So we look at the three-day rolling weighted average. And if you have, over the last ten years, certain values, essentially, in ten years, one out of ten, we look at the highest value in the last ten years. That's the 90/10.

CHAIRMAN GOLDNER: Thank you.

DR. WALKER: And that ensures that in 90 percent of the cases, your projected load is not going to exceed that.

CHAIRMAN GOLDNER: Thank you. That was helpful.

MR. FREEMAN: Okay. So I think the next slide -- actually, this is the last slide. I'd just like to conclude that the previous slide on solutions, when you look at the DSP, the solutions that were presented in the DSP are really based on the process, and then the process leads to the capital expenditure to ensure that those solutions can be put in place.

And so I will turn it to my colleague, Mr. Renard, to talk about the capital expenditure summaries and some other issues. Unless there are other questions, I cede my time.

CHAIRMAN GOLDNER: Anything else? Please proceed. Thank you, Mr. Freeman.

MR. RENAUD: Thank you, Mr. Freeman. And good morning. Paul Renaud, Vice President of Distribution Engineering.

I think in that last session last week you asked a question and, I think, Commissioner Goldner, on us categorizing investments for you, so I'm going to walk through that a little bit today.

You know, we -- this will be the same -- actually, the first slide you see will be the same slide you'll see in Ms. Botelho's answer to your question formally, but I will talk in a little bit more detail on it, and you'll also have more information filed in a PUC request.

But we do categorize these. These aren't something we came up just -- came up with just for this question. We use these categories -- categories as a standard throughout the Company so we understand where we're spending money and how we're spending money, and, you know, what's driving investment in the system.

You know, I will note that it's -- we do categorize based on the primary driver of a project, but as both Mr. Coates and Mr. Freeman said, there are other things and other objectives that we will focus on when we're doing projects. So, just as an example, a customer-driven project, the whole goal of connecting a new customer is to ensure that existing customers aren't harmed by that and the reliability is maintained. So it is a reliability-driven project, but it gets categorized as a customer-driven project.

And there's other examples we can talk about in this same way. But primary driver is how we categorize these, so we know how we're spending our dollars.

So turning to the slide here. You know, I'm going to focus first on the left. We've categorized our investment, and this is referring to Bates page 2172. This isn't the exact same chart that's on that page. That chart shows a breakdown -- a five-year breakdown of these numbers. This is a rollup of a '25 to '29 capital investment. I'll also point out that that chart doesn't include one component that I'll mention.

Here, we have four components of our total plan. Our core capital operations, so those are really the -- the base project that we do, the poles, wires, substation equipment. That's the equipment that we need to serve the customers.

And then we have core capital operation support. Those are kind of the other support functions and spending that we need to make all our operations work efficiently, and that would include things like facilities. It includes fleet. It includes information technology investments. It includes customer group, customer care shared services for how we interact with customers, and it includes telecommunication type of equipment, radios, fiber, and those type of things.

So those would be captioned under core capital operation support. That's the component not in the DSP chart on 21 -- on Bates page 2172.

So just focusing a little bit on that, you see -- of course, our core capital is the bulk -- is the bulk of what we spend, 78 percent of our dollars, and we want to maximize that, of course, and try to minimize some of the operation support as much as we can. The operation support is 16 percent of our total capital. We do have the other two components that we filed in this case, the incremental grid mod and our incremental resiliency.

I will start with the resiliency. That's a $70 million piece, about 4 percent. I would turn this over to Ms. Ntakou at this point to give a little brief, but she had to step out for a time. If there's some questions, she'll be back.

But that's really to focus on -- and this is on Bates page 2149 of the DSP, where this discussion starts, and this is to -- based on an analysis done on the worst performing segments of our system in order to maximize the dollars. This is to focus on 48 out of 470 zones in a program to target the most valuable and the highest return with those segments, focused on the reliability.

So then I would ask, if I could, Ms. Schilling, who's on the virtual here, to talk just briefly on the grid mod investments.

MS. SCHILLING: Good morning. Can you hear me okay?

MR. RENAUD: Yes.

MS. SCHILLING: Okay. So the incremental grid mod program is composed of three different components. They are described in the DSP starting on Page 02165. And the first component is a Volt/VAR optimization program that -- where we would install field equipment, so capacitor banks, regulators, substation upgrades, and the purpose is to improve how we manage voltage on the system, so the -- increasing the efficiency of how power is delivered reduces the energy needs of the delivery. So it reduces line losses and also has an impact on reducing peak loads. So the Volt/VAR optimization program is one of the key components of the grid mod program.

The second is a Distributed Energy Resource Management System. So, you know, in New Hampshire, we have a distribution management system, which is a moving -- a functioning real-time model of the system. The Distributed Energy Resource Management System, or DERMS, would be interfaced with that DMS to manage customer and Eversource, if there were any, owned distributed net energy resources, to be able to control them for multiple-use cases on the system. So it's kind of a control room application that allows us to have communication and control and send signals to solar or batteries or demand response, like Wi-Fi thermostats and water heaters in customers' homes. So that second component is the DERMS.

The third component is system planning tools. So Dr. Walker talked about kind of the process that his team goes through to forecast load and generation on the system, so this would add some more kind of sophisticated analytical tools to support those activities and increase our ability to do -- to do probabilistic planning. It also enables more sophisticated interconnection processing, as well as hosting capacity-type analysis that we can provide on the system. So those are the three components of the 35 million over five years.

CHAIRMAN GOLDNER: Okay. Thank you.

MR. RENAUD: So then I'll turn to the right side and break down our core capital investments a little bit more. And these -- we are -- you will get more detail on this in our response to PUC RR-27, which you'll have a breakdown of what I'm going to go through now.

The -- the -- the operations, we further break these categories -- and we even go beyond this, but we further break these down into -- starting with a basic business, which is on the right, the top -- the largest portion at the top right, $390 million. On that basic business, those include categories of other communication providers, Comcast and those, where we have to do work because of existing conditions. If there's car/pole accidents, for instance, there's insurance claims. We have to do work because of vehicle hits, things like that. That will go in our basic business. We, of course, try to recover that from folks. It's not always successful, but we do work hard to get that money back.

We do pre-capitalize distribution transformers, not the power transformers at the station, but distribution pole tops and the -- and a small amount of transformers, so those are a pre-capitalized item every year, which is one of the biggest components of this basic business category.

Two -- two others, a very important piece of our basic business, are emergent equipment failures. We have two categories for that. One is for line, and one is for substation. So the emergent failure line item for distribution lines is the largest component of basic business category. Then we have environmental and small capitalized tools that are also in that category.

So next, moving down around -- clockwise around the chart here, $156 million is for new customer. That is to serve new customers that come along. We do have reimbursements to customers for -- for everything we do.

Continuing down along at the bottom, you see our peak loading capacity, 202 million, about 16 percent. And here I'll just pause and give you a little comparison, because there was a discussion about, you know, what our investment needs are compared to peak -- peak load growth.

As you can see, though, it's fairly small, if you look at just 16 percent of the core capital. If you include core capital operation support, it's about 13.2 percent. And then if you include the grid mod and the resiliency components that we're adding in in the rate case, that goes down to about 12.3 percent. So relatively small.

And I'll just kind of reiterate my point, either when we're doing -- and to Mr. Freeman's point, when we're doing peak load capacity projects, we're looking at liability issues that we should be solving at the same time, and if it's a station job, we need to replace related capacity. So some of those would be reliability regime in that. But the peak load is the primary driver.

So then moving on to the biggest component of our core capital is reliability, and $513 million over the five years, 40 percent. We did break out CCI pole replacement. Our pole replacement program is in -- is in the reliability category. CCI pole replacement would normally be in the reliability category, so since it was a separately approved category, we just broke it out for this purpose.

You know, that -- that breaks out into our -- our distribution automation program that we talked about. We have a distribution line component in there, which -- which is one of the larger components. We have a distribution right-of-way component, where we talked about moving lines that are problematic out to streets, if -- if possible, if that's the right solution as we go through our -- our SPC process.

We have a distribution substation reliability, which, actually, now is our biggest component of the reliability. We're really focused on transformer assets at this point. And then I mentioned CCI.

So those are the components of reliability that -- that you'll see in our plan.

CMSR. CHATTOPADHYAY: Question.

MR. RENAUD: Yes.

CMSR. CHATTOPADHYAY: Would it be possible to provide a similar chart for, let's say, 2021 to 2024?

MR. RENAUD: You will have that, and we have provided that in the Record Request 27 -- PUC 27.

CMSR. CHATTOPADHYAY: In a chart form like this?

MR. RENAUD: It's in a table form. We

can put it in a chart form if you want, yes.

CMSR. CHATTOPADHYAY: Yes.

CHAIRMAN GOLDNER: Just following up on that, just from a numerical perspective. I'm searching for 27 right now. I don't see it immediately, but what -- how would the total compare, 1.6 billion, versus what it would have been in 2019?

MR. RENAUD: So that's a five-year total that -- you're asking for the five-year total from 2019 on?

CHAIRMAN GOLDNER: From the prior rate case, yeah.

MR. RENAUD: I can get that, not very -- at my fingertips, but we'll provide it.

CHAIRMAN GOLDNER: Yeah, that will be very helpful. Just, you know, what was it last time versus what was it this time. That's a helpful reference on a five-year basis.

MR. RENAUD: Sure.

CHAIRMAN GOLDNER: Thank you for that.

And my second question -- anyone can answer. So how much of this that we're looking at here, the 1.6 billion, would fall into PBR and how much would not?

MR. HORTON: Doug Horton with Eversource. I can start. Ms. Botelho, please chime in.

So if we're looking at this chart -- and I believe this is one of the follow-up questions you had asked, which we intend to put in writing just to try to make it very clear and distinct. But the way I would say it is that all of the blue, which is the core capital operation support for capital operations, that is -- well, I would say -- first, let me take a step back.

All and any capital would be a component of the K-bar, to the extent that K-bar provides recovery of that capital. We're not proposing that there would be a separate reconciling mechanism outside of the K-bar. So that the way that we originally presented the K-bar is that the blue-shaded categories here would be part of the K-bar calculation and part of the K-bar cap that we presented in Exhibit ES-DPH-2. Then what we have proposed is that, if the PUC, through this rate case, supports our pursuit of the incremental grid modernization/ gold bar optimization, so the red on the left, and/or the incremental resiliency, so the 70 million on the left, those investments, if supported, would also flow through the K-bar, and would flow through the K-bar by us adjusting that cap presented in Exhibit ES-DPH-2.

So that one of the follow-up questions was essentially, show us what's the cap as proposed, show us what's the cap if grid modernization is supported. Those would be two known -- known quantities today.

The only other exceptions to that, but that would still flow through the K-bar, would be co-optimization projects and Company-owned solar. Company-owned solar, as Mr. Belden mentioned, would be a separate process under which we would present to the PUC separately for review and approval. And to the extent that that gets approved, similarly, to the co-optimization, any costs that would be recoverable would then just flow through the K-bar mechanism.

And the way that each of those two categories would work -- the two categories being Company-owned solar or co-optimization efforts -- those would flow through the K-bar by the similar adjustment to the way that the cap would be calculated.

In other words, we would set the cap today, and then in the event either of those things happen, we have a Company-owned solar project that gets approved for us to move forward, or we have a co-optimization project that, through this process, gets approved, that, yes, you know, it would be allowed to flow through the mechanism, there would just be an adjustment to the cap so the K-bar wouldn't be capped out by the inclusion of those initiatives.

CHAIRMAN GOLDNER: Okay. Let me see if I can repeat that back. So the blue portion here, both the dark and the light blue, are both in the K-bar that you presented last week, and those were the fixed values by year that the Company presented.

If there -- there would be a separate

review and separate process for Company-owned solar and the co-optimization, where the Company would come in between now and 2029 and would present their proposal. If the proposal was approved, then it would increase the K-bar value for the relevant year, and that's the way that part works.

For the red and the yellow on this chart, so the incremental grid mod and incremental resiliency, how would that work again?

MR. HORTON: So it would work similar to the first two categories. So all that would happen is -- the way we had presented it is, should the PUC, as part of this rate case proceeding, reach a conclusion to support those investments that are in the red and the yellow, so incremental grid modernization, gold bar optimization is the red, incremental resiliency is the yellow, so 105 million.

If, through this rate case process, the Commission were to conclude, yes, those are worthy infrastructure investments to pursue, then we would recast that K-bar cap today and include those investments, just like we have the blue-shaded colors included today. It's just simply to say that we're -- our base K-bar wouldn't include those. These projects, although valuable, would be de-prioritized, unless the K-bar were adjusted to accommodate them.

And so we would do that, effectively, with a decision in this order. We would say, okay, the K-bar mechanism and the cap upon that K-bar mechanism will be set to reflect those planned investments.

CHAIRMAN GOLDNER: Okay. Said only slightly differently, if the Commission were to approve the 35 and the 70 million in incremental upgrade grid mod and incremental resiliency, that would have the effect, in this rate case, of increasing each of the yearly values of the K-bar?

MR. HORTON: Correct. It would increase the amount that could flow through the K-bar. And I only say that distinction because the K-bar, in the end, is going to be based on what's actually in service. It's the cap that would be adjusted today to reflect the planned activity into the future.

CHAIRMAN GOLDNER: Okay. And that would -- so that would enter into the rate case K-bar cap. And then, remind me again, please, if the -- the cap is set to, let's just say, a value of 200, and the Company only spends 190, is the Company entitled to the 200 or the 190?

MR. HORTON: It would be to the 190.

CHAIRMAN GOLDNER: Okay. So the cap is truly a cap. It's not the known value that the Company would charge.

MR. HORTON: Exactly. The K-bar is based -- the actual -- we're presenting our estimate of the K-bar, and we're presenting a K-bar cap. And that K-bar cap would be set today. But each year the k-bar would be in effect, it would only be based on the actual additions, with the exception of that one first transition year that Mr. Kallen was talking about last time, but a detail not to get us lost on this. The K-bar is based on actual additions over the course of the PBR term.

CHAIRMAN GOLDNER: Okay. Very good. And my only comment -- and this is a little bit of a repeat from before. But my encouragement, at least for the Commission's benefit, to any K-bar proposal that would come before us would be a cap value, not cap plus 12 percent or 10 percent or some other percent. Just let us know what that cap is. That would be the request from the Commission in terms of our visibility in terms of what the max is.

MR. HORTON: Yes, sir.

CHAIRMAN GOLDNER: Thank you.

Yes.

CMSR. CHATTOPADHYAY: Again, I'm trying to capture what is being presented here, so the -- all of these costs, the blue, the red, and orange or yellow, they are all part of the K-bar?

MR. HORTON: They would all be part of the K-bar, correct.

CMSR. CHATTOPADHYAY: And for the solar project that the Company is thinking about, as well as the co-optimization, you know, project that you talk about in your -- in the testimony, which is in 02011, or near abouts, it's -- those also will be part of K-bar?

MR. HORTON: They would be part of K-bar. And I think, maybe to try to simplify it, and we will -- this has clearly created confusion, and we see that, and that is one of the follow-up requests we have, and I think it will help putting it on paper and hopefully simplify.

But the way that I think of it is the K-bar is a capital support mechanism, so any capital would be reflected in the K-bar, knowing that the K-bar is not dollar for dollar.

So what we're trying to do in the initial proceeding is, we've designed the K-bar to reflect our core investments and the core capital expenditures, which are the blue-shaded areas. And then we've identified three other categories that wouldn't be pursued under just that base operation of the K-bar. Those three categories are the incremental grid modernization investments, so the red and the yellow. The second category is co-optimization, and the third category is the Company-owned solar.

So, really, what we're trying to do with those three categories is to allow -- if we move forward, if they get supported, we would just simply be tweaking the K-bar formula to allow for those capital costs to flow through the formula and not to be, essentially, capped out.

In other words, we're setting a cap now, to Chair Goldner's direction, wanting to know what that cap is, which we've calculated in Exhibit ES-DPH-2. And if we move forward with the Commission's blessing on any of those three things, which would cause us to be capped out, we're simply saying, well, if we are encouraged to move forward with these projects, we would do so and then adjust the cap. If we don't spend the money, it wouldn't go through the K-bar, because it's based on actuals. It would only be allowing that cap to be reflective of the support to move forward with those investments, and each has a little bit different flavor to them.

CMSR. CHATTOPADHYAY: Okay. Thank you. Let me summarize. I think it's import -- that was very helpful.

Essentially, the K-bar, as set, includes the blue and the red?

MR. HORTON: Just the blue.

CMSR. CHATTOPADHYAY: Just the blue. Okay.

MR. HORTON: Just the blue.

CMSR. CHATTOPADHYAY: But you're also saying, if the other projects are undertaken, allow us to change the K-bar; that's what you're saying?

MR. HORTON: That's what we're saying. You got it, yes.

CMSR. CHATTOPADHYAY: Thank you.

CHAIRMAN GOLDNER: And those community-owned solar or co-optimization projects would come in an annual filing?

MR. HORTON: The community-owned -- the Company-owned solar projects would be a separate process that would not move forward, except for that separate process.

The co-optimization projects, what we envision there -- and there are not many, but they could be sizeable. I believe we have two on our radar currently. That would be -- again, if this is adopted in this proceeding, that would be more of an annual compliance process, where we would update the Commission that this project is intended to happen next year, providing insight and clarity. We wouldn't be seeking preauthorization or pre-approval. It would just be a notification that these projects are coming, and then the K-bar -- once in service, the K-bar we present would do what Commissioner Chattopadhyay just said, that we would, effectively, then adjust the K-bar, once the additions have been made, to adjust the cap to reflect those additions have been made.

So the co-optimization is just a little -- it doesn't -- we're not asking for, like, a separate preauthorization or pre-approval, other than, again, as part of this proceeding, the acknowledgement that -- realizing these projects, although rare, can be significant and would potentially cause us to go over the cap when there's good reason for us to adjust the cap to allow for them to flow through.

CMSR. CHATTOPADHYAY: For the co-optimization projects, it's an annual process, but that annual process would also allow the Commission to determine whether those are prudently incurred?

MR. HORTON: Our vision is -- again, for administrative efficiency, that the K-bar, as it's operating, isn't providing dollar-for-dollar recovery of any individual or any one investment. So our -- the way we're viewing the K-bar would be that that prudency review would be undertaken at the next rate case, as it is today.

So that we wouldn't be intending to at least present for the Commission's review with each K-bar the prudence of any capital additions along the way, because part of what we're trying to achieve is that administrative efficiency and to -- but still have full prudency review, and be subject to prudency review.

CMSR. CHATTOPADHYAY: I think we -- we

went through the back-and-forth the second day of the technical sessions here. I'm a little bit confused about -- so you have an annual ability to change the K-bar based on what you spend on the co-optimization projects, and you -- but -- but, ultimately, it's going to be the next rate case where you will allow the Commission or the parties to go into the spend and determine whether that was prudent or not.

And so the gray area that I'm struggling with is, when you have these annual submissions, is there a way to also say, you know, that it's -- I mean, if you're going to tell me you're going to spend a billion dollars and that's going to be changing the K-bar, at some point that is not, you know, just and reasonable or cannot be prudent, so there -- there must be a way to a certain -- that when you propose something, which you're going to be allowing us to take a look three years or four years down the road, there should be some sort of a -- some sort of way to judge whether what has been produced is just and reasonable, so that's what I'm struggling with.

MR. HORTON: I understand. And I -- I hadn't thought of it in that way, until you just said it.

I think for the co-optimization projects, again, as we're sitting here, there are not many. But I understand the concern, which would be that, again, here we're essentially saying we haven't included co-optimization infrastructure investment in the cap, so our request was to have an exception to the cap to accommodate those.

Your concern is that this -- I understand, which is, if the Commission was to give us that agreement as part of this rate case, what is to stop us from coming in in Year 2 or 3, notifying the Commission we have this opportunity that's an additional billion dollars and that would naturally flow through the cap, so -- I don't know how to accommodate that in this setting. Certainly, that's not our intention, and I'm sure we could, you know, come up with some ways to put some guardrails around it, and that's a -- I understand that mechanically would be a concern, but we haven't addressed it.

CMSR. CHATTOPADHYAY: Thank you.

MR. HORTON: But I'm certain it could be.

CHAIRMAN GOLDNER: Just following up on that a little bit. Just, traditionally, this is the kind of investment that would wait until the next rate case, and that would be maybe the conventional way of handling it.

Here, the Company is proposing that this is included in sort of an interim adjustment in the revenue requirement between 2025 and 2029. You know, where I'm -- where I'm just lost, and I think it's in the same place Commissioner Chattopadhyay was asking about, is I don't know how to approve an increase in the revenue requirement, in the K-bar, in the interim without reviewing the project, so I don't -- it's a chicken-and-egg thing, so I don't -- I just wanted to give you an opportunity to respond to that.

MR. HORTON: And I think if I -- I

understand the concern. Again, these are limited on the co-optimization side. They're limited to be few and far between, but could be significant on their own. So I'm certain there could be a way to work through that in the mechanics of the K-bar, but I don't know how to resolve for that now. I think, you know, in writing, as part of the response, we can take that back and --

CHAIRMAN GOLDNER: Yeah, we're just trying to understand, in this setting, what the Company's proposal is, and I think you made that clear, so I appreciate that.

And just a quick follow-up on the solar piece. I think what you were saying is that's not really envisioned in being in the annual process. That's really ad hoc. You come up with an opportunity and you present that, as Unitil did, when and -- when the presentation or when the proposal is available.

MR. HORTON: Exactly. And then the result of that proceeding, which would be a separate process, would then just allow for that project to flow through the K-bar, but after having been -- gone through that proceeding before you.

CHAIRMAN GOLDNER: And I think the Company said earlier that this is, in the Company's mind, clearly a 374-G. It would mirror the Unitil proposal, and so in the Company's mind, that's very -- a very closer process.

MR. HORTON: Yes.

CHAIRMAN GOLDNER: Okay. Thank you.

CMSR. CHATTOPADHYAY: And --

CHAIRMAN GOLDNER: Yes.

CMSR. CHATTOPADHYAY: I suppose the co-optimization projects, why can them -- or projects, why can them be also treated like the solar? And so you have a process where we will have the ability to see whether it's prudent or not, and then it can go into the K-bar.

MR. HORTON: And I think they could. That wasn't our original -- because of the reasons that I said, but I think that certainly is a process that could work.

CMSR. CHATTOPADHYAY: Thank you.

CHAIRMAN GOLDNER: Okay. This is a

really good slide, so thank you for that.

MR. RENAUD: So no other questions on that slide? We can move on?

CHAIRMAN GOLDNER: We might come back to it later, but I think for now, we can move on.

MR. RENAUD: So we can go to the next slide, then. So sticking with the questions you asked about our investment, why our investment, in light of load growth, you know, discussions about overbuilding and gold-plating and those types of things, we did want to talk a little bit about -- about the -- this process that we underwent and why, you know, the aging condition of our system and our standards. You know, all the investments that we've talked about, Mr. Freeman talked about, is grounded in criteria. I think we mentioned this last week, standards that we bill to and that are outlined, and that's how we determine how to design our projects.

So, you know, as part of the Settlement Agreement in the last rate case, we -- we hired a consultant, an independent consultant, to come in and review our practices and procedures, review those standards. There was a lot of discussion on our standards of were they appropriate, were they overbuilding or not.

So this -- this report, TRC was the company that did the analysis, and they filed a report. That report is available to the -- to the parties in response to OCA 3-2. But just to -- you know, specifically, they came in and looked at these items that are bulleted here: Use of distribution-class steel poles as a standard in off-road right-of-way. Use of Class 2 wood poles -- and Class 2 are bigger -- bigger diameter, stronger poles that we put in the system -- and as a standard for roadside primary distribution, where we're not -- we're not talking about putting steel poles on roadside. Those are limited to right-of-way at this point. Use of spacer cable as a standard for overhead conductors.

So if folks don't know what spacer cable is, that's a bundled conductor that you'll see. It's got a messenger, and the phases are in close proximity to each other, which very strong, very sturdy construction is used, especially in heavily treed areas.

The use of fiberglass crossarms, planning standards for line relocation and reconductoring activities. Substation transformer and circuit breaker replacement processes, and then vegetation management processes on top of that.

So I pulled some key findings from that report. These are -- these are right out of the report on system conditions. So I'm just going to go through this. I have three slides here. I really only focused on this first one, because it really kind of comes to the -- to the system and their key findings and why we're proposing the investment that we're proposing in the system.

Many distribution components are beyond their expected life, require replacements to maintain system reliability and resilience. A substantial number of the wood poles, circuits with a primary conductor, substation breakers and substation transformers are at the end of their lives, and we have charts that are in the DSP that show these statistics.

Many wood poles are structure overloaded due to their age and number of attachments to poles as they age, and whether they shrink, they lose strength. That's why we have inspection. That's why the industry inspects poles periodically, because they lose strength over time.

Many circuit lines in the right-of-way are inaccessible due to location and difficult to maintain. So we do look closely at our rights-of-way. Many times it is the right place for a line, but it is hard to access in times when something happens, so the stronger construction in those areas is warranted.

And then trees and canopy are in close proximity to distribution system. Of course, we know that here. And it makes lines vulnerable to outages.

So the recommendations here are really to accelerate the replacement of our aged equipment. That includes poles, circuit breakers, transformers, with systemic plans, which we've done in our long-range plan and our DSP.

Replace woods that are structurally overloaded 90 percent or more. We do our inspection program to come up with the numbers that we file in the plan, including the CCI, which -- which I'll just add a commentary on CCI poles. We're are actually replacing fewer poles than we projected, which is good. We projected that we would have 5 to 7 percent, which is the number that we would have to replace during that process, and we are in the 2 to 3 percent range. So we're not replacing as many as we thought we had to, so that's a good outcome there.

Increasing vegetation management, not really a part of this proceeding here, but -- and then consolidate current resilience hardening efforts into an overarching program. Again, which we've done here as part of our DSP and, really, why we filed this as part of this case.

So if you could move to the next

slide, please.

So I'll just highlight on this page, just the next two go into some details on their recommendations in specific areas. But, as Mr. Lavelle [sic] went through the distribution planning, you know, I think -- I think they cooperated in areas for what we do, and they did -- they did tie it directly to reliability.

If you look at the recommendations, I'll -- I'll kind of focus -- reduce the number of feeders without the capability to allow for circuit reconfiguration and load pickup throughout the system.

So we have focused on that, and we talked about that a bit here, building ties redundancy in order to help us restore the bulk of customers faster.

And I think we go to the next page there, which just talks about the benefits of steel poles. And this is according, again, to TRC, the consultant, and their view of industry best practices, which was really why they were brought in to compare how we're doing things against what the industry is doing.

So I think -- I think with that, I'll stop, and if there's any questions, we can go there, or we can go back to any topics we covered here in the presentation.

CHAIRMAN GOLDNER: Commissioner Chattopadhyay, any questions? (No response.)

Okay. I think we're at a -- pretty close to a natural stopping place.

Attorney Chiavara, what would the Company envision that it would like to do after lunch?

MS. CHIAVARA: At this time, the Company is ready for Commissioner questions.

CHAIRMAN GOLDNER: Okay. I think we received some record requests last night, but those were all, I think, related to cap X, so we can -- any questions on that we can defer to a following PHC, so that was okay.

And then the clerks had sent us two PowerPoints, the one that we've just gone through, and one where the Company had answered Commissioner questions from last week. It's a lot to process. I just flipped through it. Is that something that the Company would want to maybe give us a high-level overview of and then give us a chance to study and then come back in a subsequent session, or how did you want to address the answers to the questions?

MS. CHIAVARA: I believe we can walk through that today if you would like.

MS. BOTELHO: Yeah. We can do whatever you prefer. There is a lot of information. It's directly responsive to your follow-up request, so a lot of information. You asked for a side-by-side comparison.

I mean, it may make sense for -- if you want to take it back, and we can come back for questions. I can orient you on what we provided, if that makes sense, and then you'll have another opportunity to ask questions on it. There's a lot of material there, so I just want to be sensitive to the fact that you just received it.

CHAIRMAN GOLDNER: Oh, thank you. I think -- Commissioner Chattopadhyay and I can talk at the lunch break. It looks like the kind of thing where we would want some time to study it and then maybe follow up with the Company in a subsequent technical session. There's a lot of information here, and we appreciate the prompt response to last week's questions.

Okay. Let's do this. Let's take a one-hour lunch break, returning at 1:00 p.m.

(Luncheon recess taken.)

CHAIRMAN GOLDNER: Okay. We'll go back on the record and begin with Commissioner questions. After Commissioner questions, we'll provide an opportunity for any of the participants to ask any questions of the parties, and we'll adjourn. So I'll start.

We talked a little bit about the Company's solar -- Company on solar plans, and nowhere in the file, and it wasn't mentioned earlier today that I caught, anyway, did the Company discuss its long-term, Company-owned solar plan.

Does the Company have one?

MR. BELDEN: So I can speak to that.

I would say at this point, the Company is planning something preliminary, and we'll be filing something as a pilot. Based on the results of that pilot, we would be developing a long-term plan.

CHAIRMAN GOLDNER: Okay. Is the pilot in New Hampshire or elsewhere?

MR. BELDEN: It would be in New Hampshire.

CHAIRMAN GOLDNER: Okay. Does the Company have defined Company-owned solar plans in other states?

MR. BELDEN: The Company currently owns 22 solar projects in Massachusetts that were developed in the last decade, so our last system went online in 2018.

We reached our legislative tab for Company-owned solar in Massachusetts, so we have no further plans at this point.

CHAIRMAN GOLDNER: Okay. And that is 22 facilities, I think you said. How many -- what's the capacity of those?

MR. BELDEN: Those are 70 megawatts

total.

CHAIRMAN GOLDNER: How many?

MR. BELDEN: 70, 7-0.

CHAIRMAN GOLDNER: Okay. Thank you.

Next question is related to the DER. Is there a unified view that the Commission and the parties can see that incorporates the Company's forecast of the DER implementation and the resulting hardware/software counterbalanced against the benefits? Is there sort of a unified view somewhere that we can see?

DR. WALKER: Just to clarify. I'm not entirely sure what you're looking for.

CHAIRMAN GOLDNER: So in the filing -- and it looked like there was about $25 million worth of costs, so the 35 -- I don't have the chart up yet -- of the 35, I think I saw in grid modernization 25 was under DERMS, so there's some costs associated with it, and I'm just trying to understand the benefits and costs and how the Company looked at that overall picture.

DR. WALKER: I'll have to refer to Ms. Schilling on the DERMS topic.

MS. SCHILLING: Okay. Good afternoon. Yeah -- no, thanks for the question.

So just to be clear, the total grid mod is 35 million for the five years. Of that, 8.5 is the distributed -- is the DERMS. And I think your question, if I understood it correctly, so correct me if I'm wrong, is that have we done any cost/benefit on would we expect to see more than $8.5 million worth of benefit associated with $8.5 million worth of cost; is that your question?

CHAIRMAN GOLDNER: Correct. Yes.

MS. SCHILLING: We have not, to date, done any formal cost/benefit analysis, so we -- there's nothing like that we could -- that we put together that we would be able to produce, but in -- you know, in our justification of the technology, the benefits are that if -- if we are able to control, let's say, an aggregated number of water heaters or a large-scale solar facility, that that would contribute to the benefit on the distribution system, and that would then go into the planning process. It would have those kinds of associated benefits of grid management. But we haven't quantified the value of that, no.

CHAIRMAN GOLDNER: Okay. Thank you for that. I would -- that's just always something that's interesting to the Commission to have, you know, discrete elements with a cost/benefit analysis so we can understand what's being proposed and that -- that balancing that, ultimately, we're asked to do.

Okay. Thank you. That's helpful.

MS. SCHILLING: If it's helpful, we could try and summarize that in writing, the drivers of benefit relative to the cost, and put -- and see if there's some way to, at least based on our understanding of the system, try to quantify that in some way. We just haven't done it to date.

CHAIRMAN GOLDNER: Okay. Thank you. Yeah, ultimately, when we -- when we look at this in the final hearing process, we would definitely want to understand the various elements and the cost/benefit. That's just one that came to mind, because I thought I had captured 25 million for

DERMS. It sounds like it was 8.5.

But in any case, each element of the grid modernization and the other pieces, it's just helpful to know how the Company views the cost and benefit, so thank you.

MS. SCHILLING: Absolutely.

CHAIRMAN GOLDNER: Thank you.

Okay. Okay. Moving to resiliency investments, which I captured as targeted under-grounding, reconductoring and vegetation management. There's 48 projects shown in the filing. I think it's Bates pages 2003 and 2004. Is -- are these 48 projects, is that aligned to the 513 million that we looked at this morning in that circular chart, or is that -- are those -- is that a subset, or there's different things? How -- how do I think about those 48 projects and the 513 that you showed on the chart?

DR. NTAKOU: So the -- this is Elli Ntakou for Eversource.

The 48 projects correspond to a $150 million plan, which is a ten-year plan. So in the five-year chart that you saw, it's the yellow

$50 million portion.

CHAIRMAN GOLDNER: I'm sorry? How much again?

DR. NTAKOU: It's the yellow, 50 million -- 70 million.

CHAIRMAN GOLDNER: 70 million.

DR. NTAKOU: 70 million. Sorry.

CHAIRMAN GOLDNER: Okay. So that's -- so 70 million -- so that's -- incremental resiliency is this 70 million. Okay.

Okay. So what I was confused about was the reliability portion is the 513, so I was mixing my metaphors there. And the 48 projects are actually resiliency, which is 70 million. Thank you for that clarification.

So just to repeat that back, 70 million was the five-year plan. 150 was the ten-year plan.

DR. NTAKOU: Right.

CHAIRMAN GOLDNER: Okay. Thank you.

On Bates 1991, there's discussion of the advanced forecasting system, which shows up in grid modernization. Does the Company have an ask with respect to advanced forecasting system, or is this something that you're just advising us, that ultimately gets baked into a grid modernization?

DR. WALKER: There is a portion of the grid modernization that's attributed to that. For the specific numbers -- Ms. Schilling, are you still here?

The question was, of the grid modernization funds, how much of that is contributed to the advance forecasting?

MS. SCHILLING: Give me a sec.

4 million.

CHAIRMAN GOLDNER: Thank you. And this is very helpful, because now you said 35 million was grid modernization, 8.5 was DERMS, 4 million was forecasting. That leaves hosting capacity, interconnection automation and VBO as the others.

Can you maybe just walk us through what each of those are and how that sums to 35?

MS. SCHILLING: Sure. The 4 -- I'm sorry if I wasn't clear. The 4 million is the sum total of hosting capacity, interconnection, automation and system planning tools, so those -- that as a total is 4. So the remainder is 22.5, which is all VAR optimization.

CHAIRMAN GOLDNER: Perfect. Thank you. And then the engineering question. There was an attempt made to describe this to the Commission previously, and, unfortunately, I didn't quite follow.

Could the engineering folks just maybe give us the high-level summary of how the VBO results in lower costs to customers as it related to benefits? Tell us more about VBO, a little bit, and how -- what the benefits are relative to the costs.

MR. FREEMAN: Ms. Schilling will do that.

CHAIRMAN GOLDNER: Oh, perfect.

MS. SCHILLING: Sure. Sure. I'd be happy to.

So the way -- when we're conducting a benefit/cost analysis for VBO, we look at the -- the sources of benefit associated with energy reduction and peak load reduction and then the associated carbon emission reduction, when you have these sources of efficiency.

So, as I mentioned, the idea of volt/VAR optimization is to increase the efficiency of delivery. So the losses -- the energy losses from, you know, source to load is -- we can calculate that in terms of kilowatt hours, and then we turn that into a dollar figure based on a -- kind of a general system-level dollar per megawatt hour of cost of energy.

We do the same for demand and then translate that into the associated carbon emissions.

So the important thing to remember here is that -- you know, the benefits depend on -- to -- you know, kind of how those costs are seen by customers. So a little bit of it is -- and it is a little portion, but every -- every customer on a VBO feeder, it takes a little less energy to supply them, so they will see it in very small -- very small -- I don't mean to over-promise this. It's not like customers are going to automatically see a noticeable bill savings, but it will show up a little bit in the delivered energy to our customers. That's one.

The other is line losses are socialized -- it's a cost, and that's kind of pancaked to all customers. So anything we can do to reduce the inefficiency of delivery is a benefit to all customers.

And then demand reduction is a benefit in terms of, you know, our costs to the transmission system are based on kind of the sum total of New Hampshire peak load, so that helps to reduce that cost.

And then, to the extent -- you know, carbon emissions we kind of included as an extra benefit, because it's a little less realized. But if you took that, we would just base that on some sort of general dollar per ton of carbon and what that cost would be generally, so it's more of a societal benefit.

CHAIRMAN GOLDNER: Okay. So I think you said you were planning to spend 22.5 million, and if you just look at the hard benefits, the line losses, efficiency, demand reduction, and so forth, how -- what would be the return on that 22.5 million in investment? Is that 50 million or 100 million, or what would that look like?

MS. SCHILLING: The benefit/cost we have done to date, using -- again, using kind of our experience in Massachusetts for a proxy of benefits, since we haven't done it yet in New Hampshire, is about a 1.2 to 1.4 benefit-to-cost ratio, and that's over 20 years, discounted back. So it's a 20-year MPV look. And so, if you were to take the 22.5, you would probably see, over the course of 20 years, probably close to $30 million of benefit.

CHAIRMAN GOLDNER: Okay. So just said differently, would it be true that the MPV of that calculation, based on the hard benefits, would be 40 million or something like that? Is that an MPV calculation, roughly?

MS. SCHILLING: It is. It is. Yeah.

CHAIRMAN GOLDNER: Okay. Thank you.

Okay. Back to resiliency for a moment. There's a -- sort of the premise for the resiliency investments, at least sort of a foundation piece of it, is this assertion that storage is getting worse and so forth.

Is there any -- is there anything in the filing that shows us that that's actually what's happening?

DR. NTAKOU: So we have in the DSP, you can find a section that talks about our climate change vulnerability study, that shows the intensification of weather because of climate change, so it would show rising temperatures. It would show increasing precipitation, as well as flooding -- not here in New Hampshire. That's primarily a problem in our other states, but this -- this one part of the work that we have done to show how the weather changes. And then we do keep track of how many event days we get in a year, what's the impact to our system, which shows the intensity of each event, and that -- that is growing. It's not going down.

We could have less event days in a year, which means less storms, but under the hood, we'd see that each day is more impactful.

CHAIRMAN GOLDNER: Okay. What -- I did see that portion in the filing. So I didn't see the foundational study that the -- the study that was done -- it's not in the filing that I could see, so I would encourage the Company to file that if they haven't already.

MS. NTAKOU: It's Bates 2156.

CHAIRMAN GOLDNER: But it's not -- the study is not in there. Some of the pieces of the study are inserted there, right, not the study itself?

DR. NTAKOU: The result of the study was done by an external consultant. It's just a dashboard that you select a variable, and you get those heat maps that we pasted in our DSP.

CHAIRMAN GOLDNER: Yeah. My encouragement would be to go back, you know, 30, 50, 100 years, whatever -- whatever data you have, and if -- if -- because if you're basing the fact that you need significant resiliency investments based on storms getting worse, then you should have strong proof that the storms are getting worse.

So my encouragement would be to go back and look at history and help the Commission understand that that premise or that assertion is true, so --

DR. NTAKOU: Yeah, we can do that. We provided in DOE 6110 a comparison of the SAIDI -- the all-in SAIDI for PSNH IEEE. So we set our third quartile pretty much every year, compared to a BlueSky SAIDI, where we set Q2 every year, so we're -- we're at grade level, but we'll get you some more data.

CHAIRMAN GOLDNER: Yeah. Thank you.

All right. I think I'm in pretty good shape. Commissioner Chattopadhyay, do you have any follow-on questions?

CMSR. CHATTOPADHYAY: Yes, I do.

So today's presentation, where the 2025-2029 capital investments were being shown for the orange and the red categories, those are actual projections, right, rather than just being illusory?

MR. RENAUD: I'm sorry. I missed the last part of your question.

CMSR. CHATTOPADHYAY: If you go to that slide, which is Slide 19 in today's presentation, the two portions which are in red and orange or yellow, these are actual projections, right? They're not just placeholders?

MR. RENAUD: Correct. Is there anything to add on that, Ms. Schilling?

MS. SCHILLING: No, we assumed those were similar to the K-bar concept kind of caps, so we would not plan to spend more than 35 in total on those three different categories.

But if we could get the same benefit for a lower cost, obviously, we would still just -- just go with what we would need to get the benefits as we articulated them.

CMSR. CHATTOPADHYAY: Because the PBR is implemented sort of annually, those numbers, I would expect them to be updated based on actual spending, right?

MS. SCHILLING: Correct.

CMSR. CHATTOPADHYAY: And so right now, what you have is a projection of what you expect would happen over the five years?

MS. SCHILLING: Correct.

CMSR. CHATTOPADHYAY: Okay. This question -- the next one is really trying to understand, you know, the Utility's thinking about having a solar project. If you think about DER projects that happen privately -- let's talk about northern -- the northern part of the state. Has the Company explored possibility of working with customers and, you know, creating the ability to use their solar projects to help solve some reliability problems? So, for example, you could think about having a -- having a -- having some sort of smart, you know -- I hesitate to call it great, but sort of smart technology that you can rely on. You can also have storage on your own, but you work with the customers to get value out of it, rather than just having a project like the one you're talking about on your own.

And I'm basically talking about -- just to expand a little bit on it, what I heard in the morning was, those are driven by private individuals. We don't have control over them.

Are there ways to work with them to give you more control, and, therefore, help solve some problems?

MR. FREEMAN: So, because part of this is related to the DERMS and our ability to orchestrate DER, I will let Ms. Schilling maybe elaborate on that.

CMSR. CHATTOPADHYAY: Okay.

MS. SCHILLING: Yeah. Thanks for the question, because I think it is important to understand, you know, what it takes to be able to leverage and use customer-owned distributed energy resources as grid assets.

So the first thing that you need is some mechanism to have real-time communication and control. So we are starting to work with customers, when they do an interconnection agreement with us, to deploy equipment on their side and our side that lets our real-time system operators have the ability to kind of see their -- their -- their facility in real-time.

And then, you know -- so once I have

that communication and control and I can send a signal to say, either turn on or turn off, or lower your output. So we have this ability to communicate and have the ability to control.

Then the second thing that you need is the DERMS, right, and the distribution management system, which we already have, so our operators know in real-time.

So let's say there was a capacity constraint, and an operator in the control room says, oh -- then the DMS lets them know, and they say, okay, I'm seeing -- I'm seeing a potential issue starting to happen on the distribution system.

So then the DERMS says, okay, well, there's a facility right there that, if you were able to dispatch a battery, you could reduce the -- the constraint on the system.

So it's the -- kind of the brain in the control room that says, I know I have a problem, and I know what resource is available to be able to meet the need.

So then the only other thing you would

need, the third thing, is an agreement with the customer to say, hey -- we wouldn't just control a customer's facility without some sort of operating agreement that gave us the ability to do so. So that third part turns into, you know, how we would be able to come to agreement with a customer to do what you said, which is to use their facility as a grid asset. That may involve some compensation. It may -- you know, it just depends on the terms of how we deal with a customer.

We aren't including any of the first or the third in this proposal, because we consider the DERMS as a foundational investment enabling the use of customer-owned assets as grid resources. But, as I said, the communication and control is something that we're starting to require going forward, and then, you know, we would just have to work with customers on the third part.

CMSR. CHATTOPADHYAY: Do you already do that in the other jurisdictions, like the two other pieces?

MS. SCHILLING: Yeah. In Massachusetts, we're also just starting to require that first part, the communication and control, but we do not have any customer-owned facilities right now that have any operating agreements where we can remotely communicate and control with them.

We have DERMS projects underway in western Mass., and planned for eastern Mass., so the DERMS technology is kind of in its early stages in Massachusetts. So we're just starting to get up to speed on implementing all three parts of it.

I would say, in Massachusetts, we have proposed a Grid Services Compensation Fund to be able to compensate customers for the use of their assets as grid resources. That is still under a lot of review and discussion in terms of the level of how much compensation, what's there, how do we tie that back to benefit on the grid, kind of getting back to your benefit/cost analysis, right? What's a fair level of compensation that's commensurate with the benefits that

they're delivering to the distribution system?
So -- but Massachusetts is the place where we're kind of on a roadmap to get to a place where we can leverage customer-owned assets as grid resources.
CMSR. CHATTOPADHYAY: And that is not the case in Connecticut?
MS. SCHILLING: No. We do not have the -- we do not have, right now, a plan for a -- either a distribution management system or a DERMS system that's kind of funded, where they're a little bit farther down on the roadmap, yeah.
CMSR. CHATTOPADHYAY: As for Massachusetts, do you have a sense of when you'll have the ability to do all the things, one, two three? Like, you know, you're in the process of enabling that, but do you have a sense when -- when you will ultimately be able to do everything?
MS. SCHILLING: We'll have full DERMS deployed across Massachusetts in 2027, so -- and the -- assuming everything continues to move forward with the Grid Services Compensation Fund,

I would say, in the latter part of 2027, we would be starting to actually deploy the assets as grid resources. So it's probably a couple years out before we're actually in operation.

CMSR. CHATTOPADHYAY: So in New Hampshire, if I understand you, DERMS is not yet in place, but -- or is it?

MS. SCHILLING: I'm sorry. Could you repeat the question? I couldn't hear.

CMSR. CHATTOPADHYAY: DERMS, is that in place in New Hampshire, or it's gonna be in place based on the capital expenditure that you just talked about in the near future, or -- you know, not necessarily near future, but the next few years if you were allowed to do that?

MS. SCHILLING: Right. It's included in the -- in the red part here in the 35.

CMSR CHATTOPADHYAY: Okay.

MS. SCHILLING: So the DERMS investment is something that we included in the ask. The plan right now is it would be towards the latter end of the five-year time horizon. So the plan would be, right now, that it wouldn't be in service until the -- probably the end of the five-year term, but that -- that's subject to kind of the need and the cost/benefit analysis. But the dollars -- the 8.5 million is included in the incremental grid mod program.

CMSR. CHATTOPADHYAY: Yeah, I understand your answer. I'm just -- I'm not sure why this would take that long, so -- and I can just leave it at that. And still, I don't understand why it's going to happen at the end of the, you know, five-year period or four-year period that is shown here. I know there are --

MS. SCHILLING: Yeah. No, that's -- yeah, totally fair. Totally fair. We -- we were kind of trying to time it relative to, you know, some of the projections. As we're starting to see more DER on the system, that that would -- you know, the benefit of it would be greater when there is more DER to control. But the technology is here today. We could -- you know, we could start a lot sooner if that -- I think, if the -- you know, kind of our stakeholders and the folks that are, you know, interested in participating, there's nothing holding us back technically from doing it sooner. It was more just trying to -- to match it to the timing of having more DER on the system.

CMSR. CHATTOPADHYAY: Okay. My last question is, as I was reading the testimony and it's -- it's always fun to see that five -- five experts are writing a testimony. That way, I know I don't have to read the first ten pages, so it makes it easier. I'm kidding, of course.

So one of the things that jumped at me was, you have a substation that tends to cater to Unitil, right?

MR. FREEMAN: Yes, we do.

CMSR. CHATTOPADHYAY: And how do you recover the costs for those? Like, is it Unitil's -- you charge Unitil for it?

How does that work out? I'm just trying to make sure it's not the Eversource ratepayers paying for something that Unitil ratepayers are benefiting from.

MR. FREEMAN: I'll defer to Mr. Dickie for this.

MR. DICKIE: Brian Dickie, Vice President of System Operations.

Yeah, so Unitil has an X plus B calculation that they use for peak load, and that's how they get charged. In the interim, they -- they put in a couple 115 to 34 stations, so they've offloaded some of our system onto their own, but they still do the calculations on -- on the transformers.

CMSR. CHATTOPADHYAY: So it's fair to assume that that substation, whatever the costs, are being picked up by Unitil?

MR. DICKIE: Some, not all of it. It's shared, right?

CMSR. CHATTOPADHYAY: Sure. I'm talking about the shared.

MR. DICKIE: Yeah, it's shared. They pick up their portion of it.

CMSR. CHATTOPADHYAY: Yeah.

MR. DICKIE: That's correct.

CMSR. CHATTOPADHYAY: That's all I have.

CHAIRMAN GOLDNER: I have one last

clean-up with Mr. Freeman. We had talked before the break about solar examples of customers that were close and far away, and what did the costs look like between the development -- developer and the Company.

MR. FREEMAN: Sure, Chairman.

So we looked over the past three years at the solar projects, the ground-mounted projects that are over 100 kilowatts and that have received interconnection agreements.

I have 16 of them. They range in cost from $1,000 to $2.2 million at the high end, so average about $430,000. And the cost per kilowatt is $280, and that's important to note because in -- in other jurisdictions, we have conducted studies of what solar developers are willing to pay us for cost of interconnection, and the consensus was $500 per kilowatt or less was their break-even point. So $280 per kilowatt is the average that New Hampshire projects have paid over the last three years.

CHAIRMAN GOLDNER: And I don't know if you were able to get it or not, but if you could just give us an example of each extreme, you know, what was kind of the minimum cost to the developer. I think you might have just said $1,000.

MR. FREEMAN: $1,000, yeah.

CHAIRMAN GOLDNER: And then the maximum cost to developers is 2.2; is that right?

MR. FREEMAN: 2.2 million. And for that project, we had to run on top of the circuit line to interconnect that project, and so the cost was for the distribution feeders.

CHAIRMAN GOLDNER: Okay. And then what was the Company cost in those two examples?

MR. FREEMAN: That was actually the cost for the Company to do that, and the developers paid.

CHAIRMAN GOLDNER: I see, so --

MR. FREEMAN: It was a Kayak -- it was Kayak developers.

CHAIRMAN GOLDNER: So the developers paid 100 percent?

MR. FREEMAN: Yes, contribution in for -- yes.

CHAIRMAN GOLDNER: And is that true in every example? Was it always that the developers paid 100 percent?

MR. FREEMAN: For all solar projects, the developer pays 100 percent of the cost to interconnect.

CHAIRMAN GOLDNER: Okay. Via Kayak. Okay. All right. Thank you for the follow-up on that one.

MR. FREEMAN: You're welcome.

CHAIRMAN GOLDNER: And now I'll just turn to the participants today to see if anyone has questions for the Company.

MR. DEXTER: I just have one or two questions.

As a result of the last rate case, the Company undertook a business process audit, and my question to the Company is: Did the business process audit impact any of the DSP, the distribution system planning that we talked about today, and if so, could you please describe how?

MR. FREEMAN: So the business process audit included several recommendations by the consultants for how to improve accounting practices, how to improve coordination between system planning and distribution engineering, tools to deploy, building models, and they're really aligned with a lot of practices that we were already implementing. We do a lot to advance planning practices with regard to how we develop processes for maintaining models and updating models with distribution engineering.

So I would say that the DSP really takes into account the spirit of a lot of what the consultants recommended, because we're already on the way to defining these capabilities, and most of the capabilities were already represented in our planning process. We have -- I can say that we have taken them into account, but not per se as a result of the audit, since we were already on the way to developing many of those practices.

MS. BOTELHO: If I could just add, so where the Company is in the process of responding to this exact question from the DOE, and DOE's at 7141, so we have not yet filed it with the DOE, but we go through a detailed review of each recommendation outlined from the business process audit and how we responded.

MR. DEXTER: Mr. Dudley would like to ask a question, please.

MR. DUDLEY: Thank you, Mr. Dexter.

Given that over the last several years, Eversource has consistently met their reliability targets, I'm trying to understand the escalation and reliability spending if Eversource is meeting most of its reliability targets.

MR. RENAUD: Yeah, I will start -- take that. You know, part of -- part of what we're looking at are the age and performance and obsolescence of our equipment. We anticipate because of that, in order to maintain, you know, a level of reliability and level of reliability indices, we -- if we were spending at the same level, we would start to see increasing failures and expect that. We don't want that. And so we are -- anticipate, through what we've described in the plan here, an accelerated replacement to catch up with the age and -- and obsolescence of the equipment.

So that really is looking at future performance and probabilities of failure, as opposed to just strictly looking at what the performance has been in the past.

MR. DUDLEY: But at the level of the spending, it -- it appears to us that asset condition is prolific throughout Eversource's service territory, but -- is that the case?

MR. RENAUD: It is. I -- when you look at age profiles of transformers, poles and those types of equipment, you'll see that we are behind, based on industry standard, lives that we anticipate. So we don't want -- we don't want to get to a point where we're seeing failures. We went to get ahead of that.

And as well as, in order to improve reliability, circuit ties is a big piece of what we're doing. It is -- we have a lot of long-range lines that -- as we described.

So part of the plan, in order to mitigate, you know, even the randomness of outages, we're not strictly looking at exactly where outages happened before. We want to make sure we're planning to be able to back up part of a system that we can't back up today.

MR. DUDLEY: But if asset condition were that critical, your SAIDI, SAIFI, CAIDI numbers would -- would be down, correct?

MR. RENAUD: Well, it might -- it might be that things start to fail faster than we can -- than we can get to them, and we don't want to put ourselves in that position. If we have a couple of transformer failures over a five-year period, and we start to see, you know, just to throw numbers out, five or ten in that same period going forward, because of -- because of the profiles, we wouldn't want to be in a position where we were trying to scramble at that point to fix that, at the expense of a customer being out of service.

MR. DUDLEY: So would you characterize Eversource's asset condition as critical?

MR. RENAUD: Well, I wouldn't say critical, but we are at a point where we feel investment's necessary so we don't get to a critical point.

MR. DUDLEY: Okay. I'm just trying to square that, Mr. Chairman, with the level of spending.

CHAIRMAN GOLDNER: Thank you, Mr. Dudley.

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

CHAIRMAN GOLDNER: Thank you. Very helpful.

Any other questions from the participants today?

MR. DEXTER: I wanted to check with Mr. Crowley on the stage --

CHAIRMAN GOLDNER: Sure.

MR. DEXTER: -- on the screen, please.

MR. CROWLEY: I don't have any questions now. I will have some questions on Thursday, but I think I'm good today.

MR. DEXTER: Thank you.

CHAIRMAN GOLDNER: Thank you, Attorney Dexter.

Attorney Kreis?

MR. KREIS: Thank you, Mr. Chairman. I don't want to get into a big back-and-forth with the Company, because, as I've already said, I have a raft of procedural concerns with giving the Company this golden opportunity to pre-try its case, but I did want to satisfy my curiosity about something.

Back -- back, I think it was in July, I got a press release from a Company named Piclo, P-i-c-l-o, and it was announcing what it called the First Online Grid Flexibility Marketplace in Connecticut, and said that, for the upcoming winter, it was working with both Eversource and United Illuminating to procure roughly 35 megawatts of energy flexibility, and compensate participants who support the grid and improve reliability, et cetera, et cetera, et cetera.

I don't want to read the whole press release, but I'm just curious whether -- I am guilty of multitasking, I apologize, but I didn't hear Eversource mention that project down in Connecticut, and I wonder if somebody from Eversource could talk a little bit about it and whether anything like that could ever happen here in New Hampshire.

MS. SCHILLING: Yeah. Sure. Thanks for the question. I can take -- I can take that.

So, yeah. No, your -- your description of the Piclo project in Connecticut was accurate and good. The genesis of that is a program in Connecticut called Innovative Energy Solutions, and the Connecticut -- the Public Utility Regulatory Authority, PURA, in Connecticut runs a process where -- what they're looking for is innovative solutions where companies like Piclo can work either with utilities or by themselves to implement, you know, programs on the grid to, in this case, reduce demand. So they were looking for companies that would be willing to kind of run a program in Connecticut to reduce demand on the system.

So in this particular project, the -- Piclo presented a concept that said, for winter, we can run a -- it's essentially like an auction. So they go out, and they recruit what they call flexible service providers, so like an EV charger or, you know, an aggregated behind-the-meter demand response program, and just bid into this platform.

And then -- and then the ones that are kind of selected based on getting the lowest cost for the resource are ones that then, in an event in the winter -- to reduce winter peak, we will call on these resources. They will -- if they show up -- if they actually reduce demands the way that they had committed to do, then they get paid. So it's a -- it's kind of an auction concept to get the lowest cost demand response possible.

As Eversource, we worked with Piclo. We helped them identify locations where said demand response would be potentially valuable to the system, and we're kind of walking with them through the process to -- to be able to recruit customers, to educate them on what the program is, and then we're helping -- they're doing the measurement and verification at the end of the day. So the funding for the program comes from -- it's a PURA program, and it's -- the funding comes through the PURA program.

I would say, as I mentioned, I think there was a question earlier about kind of the state of Connecticut relative to the DERMS and the DMS, and so Connecticut lags in the technology front on those -- you know, with respect to our ability to see this in real-time.

So the program is -- you know, we're gonna -- we're gonna use it as a way to see -- to try and understand better, if we ask 100 people to participate, how much response we actually get. So it's a good learning experience for us, both on what is the price that we need to be paying customers to show up, and then, when we do agree with the customers, how much do they actually show up in the end of the day.

So that's kind of our benefit of participating in a program. Without direct communication and control of these assets, we're less -- you know, it's a little more difficult for us to be able to count on them actually showing up. But we're using it as a good learning experience. Combined with the DERMS, a Piclo program can be a good way to try and get the lowest cost resource by having folks bid to compete to provide the services that we need.

And then -- so once we have the DERMS, this would be -- Connecticut would be another place where we could use that type of recruiting tool and then be able to count on it, because we know we have real-time visibility into their responsiveness.

MR. KREIS: Well, Ms. Schilling, you don't have to thank me for asking you a softball question like that. But I am curious whether you foresee anything like that happening here in New Hampshire.

MS. SCHILLING: Oh, absolutely. I think the foundation -- the combination of our system operators being able to have real-time visibility of what's going on of a price responsive load and finding the most cost-effective way to get the resources, it's a -- it's a good combination, and we're learning a lot in the Piclo process in Connecticut, and that's -- you know, that's one thing we endeavor to do, use best practices and bring them, you know, wherever it makes sense.

So I think that's -- you know, I do think that's a -- it's a potential program -- obviously, it needs the -- right now in Connecticut, it's funded through PURA. All customers are paying the fees for the -- for the participation, so that would need to be part of it, but I think it's -- if it's successful in Connecticut, it's something we would want to explore in other places as well.

MR. KREIS: Groovy. That's all I wanted to ask about, Mr. Chairman.

CHAIRMAN GOLDNER: Thank you. Any other questions from the participants?

MR. KRAKOFF: Thank you. I have a few questions for the participants.

I guess the first question was following up on a couple Commission questions. It was on a co-optimization project, which results in the annual K-bar adjustment.

I think previously you said that you

do not do prudency -- that a prudency review would not be conducted through that annual K-bar adjustment, and that that would occur later on in the subsequent rate case.

So I -- I guess my question for you is, if there is an adjustment to the K-bar during each annual review, then they do a prudency review later on during the subsequent rate case, is there a potential for a natural result in a downward adjustment of the K-bar if the Commission determines that the project is not prudent?

MR. HORTON: I can certainly take that. As it relates to the co-optimization investments, Commissioner Chattopadhyay had asked, you know, could there be a separate process. So, putting that aside, is there a process to evaluate for prudency prior to moving forward, which we had committed to taking back.

The idea of the K-bar is that you wouldn't be having to or trying to engage in an annual prudency review, which was one of the benefits that we see of the K-bar as compared to other regulatory frameworks, whether it be a capital tracker, a targeted capital tracker, step adjustments, something that, generally, in the past had required that prudency review annually.

So the structure of K-bar is that the prudency review would take place in the next rate case, and then would result in a prospective adjustment, just like if -- in the course of this rate case, if all of the capital documentation that we've submitted and is being reviewed, if any one of those projects is found to be imprudent, it wouldn't result in a change going back in time. It would result in a change to the authorized revenue requirement coming out of this proceeding, which would apply prospectively. And that would be -- that was the base idea.

We were asked to consider if there's a way, for valid reasons, to put some structure around the co-optimization, and there certainly are. We hadn't put that into our original proposal, but now understanding that, I guess, blind spot, if you will, that I hadn't anticipated, we certainly can attempt to resolve that, such that if the prudency review for certain types of projects that we're talking about, like co-optimization, were to happen in real-time, adjustments would take place in real-time. But that wasn't -- that is not the idea of the K-bar, to have a prudency review along the way.

MR. KRAKOFF: So, I mean, I guess -- I mean, I thought before, you said you would adjust the K-bar during each annual review, right?

MR. HORTON: Yes. So the K-bar will go into effect each year. And, again, the co-optimization, this is an important discussion, but it really is like an exception, in that we see few of these projects coming our way. We have two on our radar screens right now, so it is not extensive. This is not a major driver, as we look ahead. It's still something to address.

So what we were proposing is that, for the K-bar itself, the base operation of it, there would be an annual adjustment based on actual plant additions. And that annual adjustment wouldn't require a full prudency review of all the additions, because it's providing us revenue support for capital expenditures along the way. That's the base framework of the K-bar.

We wouldn't be expecting to or advocating that there be a prudency review for each, you know, addition made along the way. What we are talking about, though, is for the carve-out for co-optimization, the way that we had originally proposed it, also would not have required a prudency review. But based on the questioning today and the concerns that have been raised, that is one way that we could envision solving, the fact that the way we had proposed it would essentially allow for, you know, us to -- I think it was -- it would allow us to come in with an extremely large project without giving the Commission an opportunity to opine before we moved ahead.

That wasn't our intention, and I think a prudency review would be a way to solve for that for co-optimization investments.

MR. KRAKOFF: Okay. So I mean, I think it sounds like you're going to reconsider your initial proposal based on the conversation today?

MR. HORTON: My understanding is, based on conversation today and last week, yes, there are several follow-up questions that we're expecting to respond to in writing, and that was one of them.

MR. KRAKOFF: Thanks. And just a couple of other questions. I guess it was with respect to slide -- bear with me one second. Slide 15, and it was when you talked a little bit about, you know, non-wires alternatives, and how you do that cost/benefit analysis on NWAs.

I don't think you talked about it today, or if you did, I didn't hear you. But could you point me to where in the filings -- you know, you've listed out the benefits that you're using to measure the benefits when you do that cost/benefit analysis for NWAs.

DR. WALKER: We'll have to take that as an action and find the exact location. I don't know that off the top of my head.

But I can quickly talk a little bit

about the benefits that are being used in the non-wired approach.

MR. KRAKOFF: That would be great.

DR. WALKER: Yeah. So as the Company has mentioned in its filing, we have a non-wired alternative framework that outlines how the Company reviews alternatives to traditional investment. Now, this can be energy efficiency, storage, solar, spot generation, demand -- there's a whole lot of opportunity there. And we don't limit this to any technology or just one technology. I mean, a mix thereof is also possible.

And the first screen all of this must pass is a technical feasibility test, and no solution is going to be considered that doesn't address the need. If we're talking about a ten-year forecast and we have X amount of capacity, means any solution considered must meet that reliably.

And the second point that was just addressed is, what do we do in terms of the benefit/cost analysis. So the biggest driver on the benefits side for non-wired solutions for the customers is the deferral on the investment of the infrastructure.

So rather than, as an example, upgrading a substation in the next two years, you can deploy a program with an array of different technologies that pushes that out. Let's call it eight years. That defers that investment. That has an impact on the revenue requirement of the customer. We can calculate that benefit, and that is basically the largest benefit that sits against the cost of the solution.

If the solution, for example, includes solar, there are certain benefits for the generated energy that gets counted in towards it. If it is storage, we typically do not consider benefits from energy markets in the initial benefit/cost analysis. It's highly speculative on a ten-year horizon to predict how much benefit the storage system might get to actually make. And the dispatch for non-wires is not always in line with what energy markets might need, too. We all have conflicting interests, which we can't really have for a distribution asset.

So we don't typically consider that. Should those then actually end up producing some value, that's, of course, directly calculated against the cost of the non-wired solution, and drives down the cost to the ratepayers.

Yeah, but that -- that basically summarizes it. So we do evaluate the markets. We don't put that into the BCA. We look at the deferral value of the traditional solution, and that's what has to be offset by the cost. I hope that helps.

MR. KRAKOFF: Yeah, I think so. But to follow up on that, I mean, would you account for any cost related to -- any cost-related siting differences between the two projects? So, you know, I guess, not simply cost, but the difficulty --

DR. WALKER: Of course. So the projects include costs. When I do the evaluation, there's a cost assumption to procuring property, siting challenges. All of that goes into the calculation. So by the time we do the benefit/cost analysis, we typically have a relatively good understanding of what the traditional solution costs.

And for the non-wires, we start off with standard values from, for example, NREL, National Renewable Energy Laboratory, and then we can get more detailed and more detailed, down to the point that if we decide to do this, we can issue an RFP to see, for example, the volume storage, what the cost of such a solution would finally turn out to be.

And that -- that includes all the siting, land procurement, interconnection costs and everything that's associated with it.

MR. KRAKOFF: And I think before, you said you solicit some NWAs in Massachusetts, and I think you said Connecticut as well -- or you were planning to.

Did you issue RFPs in those cases?

DR. WALKER: So that depends on where those projects are in the state of development, right? Mr. Freeman had mentioned in Connecticut the currently filed with the Commission. So as soon as they get approved, then that would be the logical next step.

I don't know where we are in Massachusetts with the two. For P-Town, I am fairly certainly that we did, yes. Those were procured through an RFP.

MR. FREEMAN: Correct. And the one that's in development in Massachusetts, that one we -- that one is issued to -- to a contractor based on embeds. I think it was an RFP, also. The second one is not at the RFP stage yet. And as Mr. Walker mentioned -- Dr. Walker -- the Connecticut projects will go through the same process as we did in P-Town.

I just want to note that the non-wires are not too frequent, that Dr. Walker described. That has been filed in previous dockets in New Hampshire. We have filed it in this docket, if it's helpful. There is a docket in that sphere that outlines everything that was just described.

MR. KRAKOFF: And just one or two follow-up questions. Before, you said that basically -- if the benefit/cost ratio is over one, you selected -- I guess when you're comparing traditional to the non-wires -- it's just going with the higher BCR?

DR. WALKER: Well --

MR. KRAKOFF: Or is it not that simple?

DR. WALKER: Yeah, it's not quite that simple. I guess the first thing it needs to pass is the technical screening, all right? We're not going to take a look at the BCR if we're not sure the solution can pass the technical side, because a cheaper solution that's less reliable isn't something that we're going to be looking for.

And then even if it passes the BCA or BCR, greater one, you still have to go through RFP, and, you know, our estimate might have been wrong. The vendors might have come back with significantly higher bids that might still fail at that point.

So there's multiple checks in there to make sure that the solution we're progressing with is the most cost beneficial solution, should we go down the route of the non-wires.

MR. KRAKOFF: Okay. Thank you. Those are all my questions.

CHAIRMAN GOLDNER: Okay. Just checking one more time. Anything else?

Okay. Seeing none. I'll thank everyone for their participation today, and for the Company, we appreciate bringing both the technical experts and the executives to this -- to this session. I think we had the right people here to get the questions answered for this Pre-Hearing Technical Conference.

And this concludes day 3, having had all our PBR questions answered. We'll cancel day 4 for tomorrow, and thank everyone for their time, and this Pre-Hearing Technical Conference is adjourned. Thank you.

(Whereupon, the proceeding was concluded at 2:00 p.m.)

C E R T I F I C A T E

I, Nancy J. Theroux, LCR, RPR, do hereby certify that the foregoing transcript is a true and accurate transcription of the within proceedings, to the best of my knowledge, skill, ability and belief.

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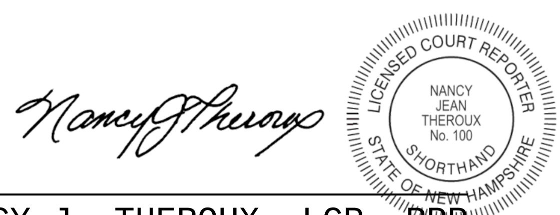

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