STATE OF VERMONT
PUBLIC UTILITY COMMISSION

CASE NUMBER 17-3142-PET

IN RE: SECOND WORKSHOP ON
UTILITY RATE REGULATION

September 12, 2017
1:30 p.m.
---
115 State Street
Montpelier, Vermont

Workshop held before the Vermont Public Utility Commission, at the Vermont State House, Room 11, 115 State Street, Montpelier, Vermont, on September 12, 2017, beginning at 1:30 p.m.

P R E S E N T

Commissioners: Anthony Z. Roisman, Chairman
Margaret Cheney
Sarah Hofmann

Staff: Thomas Knauer, Utilities Analyst
Andrea McHugh, Utilities Analyst
Kevin Fink, Policy Analyst
George Young, General Counsel

CAPITOL COURT REPORTERS, INC.
P.O. BOX 329
BURLINGTON, VERMONT 05402-0329
(802)863-6067
E-mail: info@capitolcourtreporters. Com

P A R T I C I P A N T S

Frederick Weston, Regulatory Assistance Project
Mark Lowry, Pacific Economics Group
Riley Allen, PSD
Brian Winn, PSD
Joanna White, PSD
Daniel Burke, PSD
Christine Peters, PSD
Carol Flint, PSD
Charlotte Ancel, GMP
Robert Dostis, GMP
Kristin Carlson, GMP
Doug Smith, GMP
David Westman, VEIC
Morris Silver, VEIC
Steve Farman, VPPSA
Melissa Bailey, VPPSA
Jeremy Hoff, Stowe Electric
Ellen Burt, Stowe Electric
Matt Rutherford, Stowe Electric
John Brabant, VCE
Cheryl Willette, WEC
Patty Richards, WEC
Deena Frankel, VELCO
Beth Oleks, Acadian Consulting Group
Elaine O'Grady, NESCAUM
Kim Hayden, REV
Olivia Campbell, REV
Eileen Simollardes, VGS
Lauren Hammer, VGS
Katie Orost, VEC

CHAIRMAN ROISMAN: Good afternoon, and welcome. Thank you for coming to the second one of these workshops. I am Anthony Roisman. I'm the Chairman of the Public Utility Commission. Our other two Commissioners, Sarah Hofmann and Margaret Cheney, are here; general counsel; a lot of staff, and today, because it is September, I think of this as the first day of school because today we're going to learn about alternative regulation and traditional regulation everywhere else but in Vermont to help us understand what everybody else has tried, what's failed, what's worked.

And this is not the time for you to offer us your view of why you think something that's proposed is good or bad. That will be the next session, which, although originally scheduled for the 22nd of September, we have run into a scheduling problem due to the Jewish holidays which is the second day of the Jewish New Year is the 22nd. So we will be shortly issuing you an alternative date for that.

Today we're going to hear about everything else, and at that next session you'll have your chance to talk about what you liked or didn't like about what everybody else is doing. So we're very grateful to have two very distinguished, highly educated, and

informational speakers. What I can't tell you is whether or not they're entertaining because I've not heard them. So I will leave that up to them. Anyway, thank you again, and let's start.

MR. KNAUER: Hi. I'm Tom Knauer. I'm an analyst with the Commission. I've been asked to introduce our speakers and to moderate today's workshop. So we will begin with Rick Weston. I think most people in the room know Rick or have crossed paths with him.

MR. WESTON: Swords.

MR. KNAUER: He was asked by the Commission to show up here and give a survey of nontraditional regulation. Rick is a principal at the Regulatory Assistance Project, and I have no further bio, so I will hand it over to you. After Mr. Weston we will have Mr. Mark Lowry, and we'll do an introduction when it's your turn.

MR. WESTON: Thank you, Tom. Thank you, Chairman Roisman. Commissioner, I'm not used to Commissioner. Board Members Hofmann and Cheney, thank you very much for inviting me to speak today. I'm not sure how entertaining I'll be, but, since it is the first day of school, let me say, Welcome students, and the apples you can leave on the desk afterwards.

Riley?

MR. ALLEN: I just wanted to know how you want us to interact with this. Do you want us to interrupt you with questions as we go along, or would you like to go through the entire discussion?

CHAIRMAN ROISMAN: Do it questions after you're done.

MR. WESTON: Okay, answer questions afterwards. I'm going to make this as quick as I can. I have to apologize by paraphrasing Blaise Pascal by saying that I'm sorry that the length of this presentation is a little too long. I didn't have time to write a shorter one. But I'm going to skip a bunch. You can read it. I just want to point out on each slide what I think are some key elements.

So, with that in mind, a survey of nontraditional regulation around the world, mostly in the United States, but I'll tell you some stories of some other countries as well. And the challenge, here's how we see the challenge. It's aligning -- it's a question of how best to align the private interest with the public interest. How do we get the utilities and others to do the good things that we want them to do and avoid doing the things that we don't want them to do?

So you've, I'm sure you've all seen this or heard

this before. This is Peter Bradford speaking in 1989. David Moskovitz often gets credited for the comment, but, in fact, it was Peter Bradford who, at the time, was the Chair of the New York Public Service Commission, and the question always is not merely recognizing that there are incentives but truly understanding how they work.

So just a little background. Traditional rate regulation, what we have, what here in Vermont until ten years ago or so, practiced, or a hundred years, is simply a price-setting exercise. You go through all kinds of accounting machinations to find out in the end what the prices should be, and, once the prices are set, the utility makes money by selling its goods and services and by cutting its costs, two very powerful incentives, particularly when it comes to the network elements of the utility's cost of service, because the marginal costs of those network services are virtually zero in the short run. That's why we refer to them as fixed costs and not fixed in the long run, okay?

So, as a price-setting exercise, again, I just want to emphasize two incentives, to sell more of the product or to avoid reducing sales and, of course, to cut costs between rate cases. We call that the throughput incentive. It's very powerful, and it, of

course, has driven a lot of behavior in certain ways that we don't like, but over the course of the last century, it made a lot of sense, and we did what no other -- I mean, really, I shouldn't say no other, but we did create, of course, the most complex and reliable electric system in the world, and I think "Time Magazine" named it the invention of the century.

Okay. Revenue regulation is a way to tackle the throughput incentive. Sometimes it's referred to as decoupling. I'll call it revenue regulation here. As you know, it's intended to break the link between the revenues that are collected by the utility or authorized to be collected and its sales. This is about revenues. It's not about earnings.

Now, we're going to talk about how earnings adjustment mechanisms get wound into this and the effect that they can have, but, very simply, setting revenues and allowing the utility to collect only those authorized revenues means that you're talking about just the revenues, and the ultimate net income that the utility earns is a function of its ability to provide those goods and services at the least cost and, thus, if it's reducing its costs, then it's making more money or it's not losing as much money. So lower costs equal higher net income.

This should make the utility indifferent to its sales levels whatever their causes. This, we refer to this as full decoupling where everything gets caught up in it just simply by setting a revenue level. So it's weather, economic factors, could be programmatic, energy efficiency, other distributed energy resources, whatever. I just want to go through this just so you know my vocabulary. You may have other vocabulary that you've heard, and this is how I see it.

Then there is what we refer to as performance incentive mechanisms to drive specified outcomes, financial rewards and penalties associated with the achievement of outputs and outcomes that are defined through the regulatory or legislative process. We're generally agnostic to the means by which they're achieved, thus giving the actor and actors incentives, well, the ability to be entrepreneurial and creative about how to meet those goals which is what we want, I think, and they're typically overlaid on a revenue-based regulatory regime, and you'll see that in some of the, in all the examples I'll give, and thus the rewards and penalties will affect the allowed, the target or authorized revenues that the utility is allowed to keep.

Okay. So what might be some performance metrics? Just a few of them here: Reliability, customer service, power plant performance, which would be presumably, you know, through a, in addition to a fuel adjustment cost or some other purchase power arrangement. Safety, energy efficiency goals might be part of it, environmental achievements, emissions reductions, for example, and there may be others. So these are all things to think about and things that are being thought about elsewhere in the country.

So, when I think about PBR, I think about these two structural elements, revenue regulation on the one hand and performance metrics for specified outcomes on the other. I consider them the two major components of most performance-based regulatory schemes, and that's how I'm coming about it.

So, again, how can the public interest or the private interest be best aligned with the public interest? And that's what the design process is all about, and I know you've all gone through this for the last ten years and you have your ideas about how it can or can't work. Okay. So some examples, both domestic and international.

Start with the United Kingdom. You may have heard of this. It's call RIIO, revenues equals incentives

plus innovation plus outputs, implemented in 2013 after 23 years of RPI-X regulation, which might sound familiar to you if you've done any telecommunications work, but it was also a revenue-based regulatory scheme essentially setting revenues and adjusting them from year to year based on productivity and inflation and other factors. RIIO is also a revenue-based mechanism overlaid with some specified, again, performance measures, metrics for desired outcomes.

The idea here for the regulatory body, Ofgem, is to push the utilities in the UK toward more clean energy outcomes. They've got this idea about innovation and how to reward that. I don't have the details of the RIIO plan here. I'll be more than happy to get them for you, but I can tell you a couple details.

One is they are trying to remove the bias in regulated utilities toward investment in capital, the bias, obviously, against operating expenses and achieving conceivably least-cost outcomes, not through investing, but by, you know, current expenditures. They refer to it as Totex, total expenditures, and the way they're trying to get at it is to focus on, again, desired outputs rather than simply new infrastructure. One of the interesting features of the program is that

it extends the RPI-X program from five years to eight years. So it's eight years between rate cases, okay? And they're essentially saying that they are really happy to have their utilities make money doing the things that they want them to do.

So, with that, let's see. Some of the outputs that they relate to, and I'll show you the metrics page which you won't be able to read, but I can, again, send you, as you wish, more detailed information. Customer satisfaction, network safety, reliability, new connections, the sorts of things that I think you're all familiar with but also environmental impacts and other social obligations, in particular, serving at-risk and low-income customers.

You know, this is just a graphic that they -- I don't even understand it, but I thought you'd -- and here is a score card. Unreadable even when you've got a magnifying glass, but, again, all kinds of metrics. You know, did they -- you know, in certain cases it's binary, did they achieve this outcome? In other cases it's along a continuum.

Okay, revenue regulation and performance incentive mechanisms in the US. The, the states to look at are, at least the ones I'm going to concentrate on, are the ones that were both blue and cross-hatched. These are

the ones that have both revenue-based regulation for at least the network services and have performance incentive mechanisms for particular outcomes or at least are thinking about them, and, as you can see, Vermont met that, those criteria.

The green states are ones that have lost revenue adjustment mechanisms for specified impacts on their revenues, so what we used to call the ACE account here in Vermont for years, correcting for efficiency, those kinds of things. Those are those states in green.

The gray ones have performance incentives of some sort or another, with the cross-hatched, that is, and the gray ones have nothing at all. I'll say that there is something of a correlation between the blue and cross-hatched states and overall achievement in savings and use, energy efficiency.

Okay. California Pacific Gas & Electric, revenue regulation of the network services, nonweather-adjusted actual revenues compared with the authorized or target revenues plus their annual attrition and exogenous adjustments, and the over- or under-corrections are trued up annually. They do a three-year rate case, you know, one-year rate case with a future test year and then two more years of future test years, and they're established every three years, and the authorized

revenues are established on the basis of those, of that rate case, and then the annual attrition case measures changes in costs and adjusts the authorized, excuse me, authorized revenues accordingly.

For all of these, the revenues in question are the nonweather-adjusted actual revenues, except for Idaho. I'll come back to that. And all that means is whatever they collected, regardless of what the weather actually was, okay? Obviously, the test here is itself weather-normalized, okay? So, in effect, their authorized revenues are weather-normalized. Their actual revenues are not, but, when you see what happens to Idaho, you'll see that there's a risk shift there.

California, California operates according to the Weston family motto, "If it's worth doing, it's worth doing the hard way". So they've got many balancing accounts, and, in effect, they're, they're keeping a very close eye on expenditures across a variety of accounts, and it's, there's not a, not a lot of room for maneuvering on the part of the utility, okay?

So here are some of the accounts. Surpluses and deficits are amortized and refunded or collected in the next year, and it's done on a system-wide basis, so it's averaged across all customer classes. Obviously, energy procurement and, in this case, FERC transmission

charges services are treated separately as well, and the only performance incentive mechanism they have are for achievement in energy efficiency. You've probably followed the California experience. They had some controversial payments a few years back, and, you know, they've tweaked that and worked on that a bit.

Okay, Idaho, okay. They call it the fixed cost adjustment mechanism. I'll just state my own bias about that expression. No costs are fixed in the long run. We're really only talking about fixed costs, unvarying costs in the short run essentially between rate cases. The question is, How long is the term? They, their mechanism compares the authorized network revenues with weather-normalized sales. So what's going on here is that their actual revenues are adjusted for weather as if they had a weather-normal year, which means that the utility still retains the weather risk.

When you do full decoupling, everybody, the risk goes away for both customer and utility, okay, on the network stuff. We're talking about, again, the distribution system. But, in this case when they normalize their actual revenues for weather, it means that the utility is still on the hook for the hot summer/cold winter or cool summer/warm winter variation

in revenues. That, in fact, means that the utility still has some element of a throughput incentive motivating its behavior, okay?

Pretty simple. It's a, they do do the -- one of the adjustments they do is revenue per customer. In the short one we see that costs are driven, to the extent that the costs are being driven by factors other than sales, they're being driven by changes in the number of customers. So the revenue requirement will be adjusted for the number of customers. We can talk about just how that's done mathematically.

The annual adjustments are shared proportionally between the residential and commercial customers. As you noted, the large industrial and commercial customers are not, those tariffs are not in the decoupling mechanism. The diversity of the loads is such that they really feel they've got it, that they can't make those kinds of, of revenue adjustments year in, year out. It would be too variable. Let's see. Obviously, energy costs due to fuel adjustment costs, and they are required to acquire all cost-effective energy efficiency, but there are no performance metrics for that at this point.

Maryland, Baltimore Gas & Electric, I want to highlight this one because of the way they do their

reconciliations. Again, it's a network service. They have a revenue per customer method of adjusting their revenues from period to period, in fact, on a monthly basis. There are no adjustments for, you know, productivity and inflation across the years. They have a series of rate cases scheduled. What they do is they adjust their prices through surcharges on a monthly basis so that the target revenue for any one month is actually collected in that month.

They make the adjustment, as I say, in a form that we call the current method of, of revenue collection, and, as a consequence, there are no true-ups, no deferred true-ups of any sort, so there are no carrying costs. There's no regulatory risk or asset to be dealt with. As I said, no formulaic adjustments other than the RPC and no other PIMs or EE or other public policy objectives yet. I may be a little bit behind the times. This is a year or two out of date. The Commission was taking a look at performance incentive mechanisms, and I'm not sure what, if any, they've adopted.

Wisconsin Public Service, the revenue stabilization mechanism, once again, target revenues compared to actual revenues. Annual adjustments, I think they do it annually. I'll have to -- on the next

page it will say. They call it marginal, and it's, I think, I think it's just they're referring to the marginal revenue change, but they, it's not anything other than that. Obviously, as it says here, No adjustments for inflation productivity Z- or K-factors. K-factors we refer to as special factors, and there's one as opposed to, you know, tax changes and other things like that that you might see in the exogenous factors, and I'll, we're going to have an example of one in a moment.

And, again, applies to all tariffs except large commercial and industrial. They do it on a year-to-year basis, and they have a $14 million cap on changes in revenues. Overages or underages are borne either by the company or by the customers. There are no performance incentive mechanisms for Wisconsin Public Service, but there are for the other utilities who are also under revenue regulation plans in the state.

National Grid, same thing, revenue regulation for the network services, the distribution services, annual adjustments. The adjustments are made by customer class, and there are also adjustments for changes in capital expenditure. So it's, in effect, the capital account is dealt with separately, and it's maxed at

$170 million a year.

You can regard this as a kind of K-factor, again, intended to reduce or eliminate the bias between capital expenditure and operating expenditure. So the regulators are, are in on that. That's a major point of discussion every year when they, when they take a look at what the next year's authorized revenues ought to be. Obviously, energy costs for basic service customers, transmission costs, energy efficiency, low-income assistance are all treated separately either through surcharge or some other account.

Now, they do have a revenue-sharing mechanism, an earnings-sharing mechanism, I should say. It will be adjusted for earnings in excess of the ROE. It's a 50 percent sharing. Now, the increases in allowed revenues are capped at 3 percent per year, but, if it looks like there's going to be a problem, interim adjustments can be made. I don't know if any have been since this began. This was put into effect when Paul Hibbard was still Chair of the Commission. They do have an incentive up to 5 percent of program costs for meeting your energy efficiency targets and also, of course, for meeting service quality standards.

And, Hawaii, very similar, same thing, distribution revenue, target revenues matched to

actual. They're adjusted each year. In this case, the target revenue for the next year is determined by some adjustments in labor costs using productivity factors, inflation. There's a cost index for nonlabor O&M, and they will make changes in the rate base through a regulatory process for the items that you see there, and they have separate mechanisms for efficiency and power costs.

They also have an earnings-sharing mechanism to protect against excessive overall revenue collections. It's a sliding scale either way. So it's a 90 percent customer share after a 3 percent change. There are, as I said -- well, I didn't say, but I'll say it now -- provisions for capital investment if different than expectations, and there are other mid-course corrections.

Efficiency is provided by a third-party administrator who operates under its own performance contract, but there are no other PIMs, I guess we could say, but the PUC is investigating a whole series of ideas for, again, achieving the State's objectives for clean energy, and I think you're probably aware that Hawaii has been very successful in integrating a great deal of renewable energy into its system. Its fuel costs are extraordinary, so the cost-effectiveness of

alternative resources is pretty high.

My favorite place in the world, China, has just adopted revenue regulation for its state-owned enterprises, the distribution and transmission companies. They did it for one reason. They didn't think about achieving other public policy goals. They thought about improving the operational efficiency of their utilities. Since revenue regulation drives the incentive, is a very powerful incentive for cost reduction, they thought this would work.

So they're, they have had a couple pilots on it. The pilots are developing some output-specific PIMs as overlays on the revenue regulation framework, but they're rolling it out across the country this year. Just what the mechanics are are not entirely clear, but then nothing in China is anything but opaque.

Now, let's see. What do I have here? Well, they're talking about some of these performance incentive mechanisms having to do with environmental performance that have been applied to their management. I'm not sure that they strictly applied them at times. But, also, with respect to capital usage, reliability, and others, we'll see, see how that goes.

I'm not going to say much here about New York reforming the energy vision. I think you might have

something. Do you have anything to say about it?

MR. LOWRY: No, I don't talk extensively about it.

MR. WESTON: Well, let's bring back one of my colleagues, Rich Sedano who was involved in that if you'd like to hear more about that, but, again, here's another state looking at, looking at the future, rapidly changing technology, the distributed nature of energy that's growing, of course, across the country, and asking itself, What kinds of performance incentive mechanisms can we put in place, not only for the utilities, but for other actors to achieve the outcomes that the State is seeking to achieve? It's not clear to me through the use of the expression earnings adjustment mechanisms whether these will be tools that actually change the allowed revenue or change the net income, and, in my view, there's a very big difference between the two, and we can get to that.

So what you see, essentially, is revenue regulation for the network elements, and, in certain cases, some of the bricks-and-mortar power plants, but power costs are separate, managed separately and in certain cases with incentives, sharing mechanisms, and so on. I think it sounds somewhat familiar to you all.

So, very quickly, some design considerations that

you'll see differences in all these examples, and there are others besides the ones that I've shown. Obviously, the timing of the revenue adjustments. What's the cost of money? Should there be caps on them? What's the test year? How long should the plan go before there's a full rate investigation? What are the adjustment mechanisms? How do you allocate deficits and surpluses? And what other performance metrics did you put in place to achieve what it is you want to achieve?

Okay. A couple -- I'm almost done. A couple new challenges. You've heard the term, I'm sure, beneficial electrification. This is something that is at the heart of the REV process. Fuel switching in a new direction, we think it can do some good things. I think Vermont even thinks it can do some good things. This is the Vermont Comprehensive Energy Plan from last year, okay?

And so what might be an appropriate metric for beneficial electrification? Using fewer kilowatts, obviously, in efficiency you want to use fewer kilowatt hours, but the beneficial electrification goal is fewer joules, possibly by using more. This is a term that one of my colleagues developed, "emiciency". I'm not -- it's kind of clever, but there you go. And I just

threw this one question at the bottom. Is this a way of helping us, helping you think about the Tier III question? I spend my time in China, so I don't really know what some of the problems are, but it occurred to me as I thought about this last night that this may be one way to begin thinking about some of the issues that I know that you're all struggling with.

Okay, a few observations. Let's see. It's been, effective. Revenue regulation has been effective in providing cost containment and disincentive, well, incentives and disincentives to the utilities, the removal of the disincentive, the disincentive for the throughput increases. Obviously, it got my sense that overlaying performance incentives on top of revenue regulation offers a powerful tool for achieving public policy goals.

I would counsel us all to beware the consequences of features that are intended to limit the downside risks to consumers because they can also limit the upside benefits. I have some concerns about earnings-sharing mechanisms when they're applied to the net income as opposed to the revenue itself. Every time you, you alter the earnings without affecting the revenues, i.e., dealing with the underlying cost, you're removing an incentive for cost containment, and

you can think that through.

Separate costs of investment trackers can also reduce incentives for innovation and savings. Doesn't mean you shouldn't do them, but I'd say we should think long and hard about what their consequences will be. Revenue regulation and, and PBR generally give you some opportunities to implement more economically efficient, more dynamic rate designs. There's no question that the public education process, a public design process has made these programs more successful in the states where those processes have been used.

And, as you would expect to hear me say, lost revenue adjustment mechanisms don't solve the throughput problem because you still have, as long as you still have traditional regulation on the other side, the incentive to sell more or not to sell less remains. It's not that I'm suggesting that we don't want the utilities to make money. We want them, I think, to make money doing the right things, and selling more of their product might not necessarily be the right thing if it has environmental consequences that we're trying to stop.

So you can see where I'm coming from, and that's my plea. Thank you very much. I really appreciated this. Do questions now or -- sure, questions?

COMMISSIONER HOFMANN: I actually have one, Tom.

MR. KNAUER: Commissioner Hofmann.

COMMISSIONER HOFMANN: Can you -- I wrote down Slide 19, so when you get to 19, I'll remember what my question is, Rick, so --

MR. WESTON: I have no idea. It's Idaho.

COMMISSIONER HOFMANN: Okay. So they're required to acquire all cost-effective EE, but there's no performance incentives or penalties. Is there something else in place that encourages the acquisition of the cost-effective EE?

MR. WESTON: Not that I know of, but I can check for you, other than, you know, angry regulators.

COMMISSIONER HOFMANN: Okay. And then move ahead to 21, which is still Maryland. I had a couple questions about. So you were indicating that the, the -- how often does the customer's bill change, the rate on the customer's bill change?

MR. WESTON: The base rate only changes with a rate case, but the adder or credit changes every month. And I can show you. I've, in fact, I should have said this. There are several publications that RAP has that I encourage you to look at. I would have brought hard copies of them all. I don't have hard

copies of the one that actually has the numbers for Baltimore Gas & Electric, but it shows the monthly change for five years in the rate, and you're really, at the fifth decimal point, very small.

It can vary, of course, because of the weather. You know, July of this year is very different than July of last year. That could happen, but the annual, the overall annual changes have been very small, but, as a general matter, it's, the changes from month to month have been pretty small as well.

COMMISSIONER HOFMANN: Okay. So that answers my question, because I just wondered what kind of consumer outcry they'd had, but it's small, so it's not --

MR. WESTON: Well, it's been in place for, since 2007, 2008, and it, it came out in part during, for those of you who remember this or maybe not, the MADRI process, the Mid-Atlantic Demand Response Initiative, and some of the design features of their decoupling plan were vetted through that process. In my view, this is one of the most innovative because there are no carrying costs. You know, you're not carrying any deferrals forward, and you're, the utility gets its revenues, and that's that.

COMMISSIONER HOFMANN: Have they shown great savings because of no deferrals and things like that?

MR. WESTON: Well, they think they have. I mean, it's hard. I haven't seen a study on what would have happened under traditional regulation, and that counter-factual is a difficult one to develop. But the regulators feel pretty good about it and have for now ten years through two changes of administration.

MR. KNAUER: All right. Patty and then Charlotte and then Riley.

MS. RICHARDS: How do consumers feel about a surcharge in and out, especially on a monthly basis? To me, it would seem like a bit of a black box. And how do you explain that to the consumer base and get by in that this is accurate?

MR. WESTON: Now I want one of the Maryland regulators to come here and answer that question. I do know they went through a pretty intensive public education process. It's a small change from month to month, again, the fourth, third, fourth, fifth decimal point, so it has a small impact on the bills. I don't, I don't really know the answer to your question other than the educational process and given the complexity of regulation generally. I just don't know, but I'd be happy to make some phone calls for you.

MS. RICHARDS: I actually have a few questions. Can I rattle them off?

MR. KNAUER: Please, yeah.

MS. RICHARDS: Of all the models that you have, you talk about kind of carrots and sticks. Seems like more of investor-owned models. What about not-for-profits?

MR. WESTON: We'd like to think of the state-owned enterprises in China as not-for-profits, but, in fact, they are. I, I think that revenue-based regulation can work for not-for-profits as well. The issue is revenue and stabilization of revenue, making sure you're covering your, your allowed costs. I don't see why a revenue regulatory mechanism can't work equally well for consumer owned or municipally owned utilities as well. It, it gives the incentive for cost reduction which you already have, but the thing about it is you don't have to worry about sales.

When -- I'll say this. When GMP first went to its nontraditional regulatory plan, I ran into Don Rendell afterwards. This is 8 years ago. I've been with RAP for 18. So and he said that, the first thing he said to me was, It's changed our attitude. Now, I'm not -- you know, I mean, that's just Don speaking, and I'm not, I'm not -- I don't want to be seen as carrying

anybody's water, but I wasn't surprised to hear that because we don't -- our revenue is stable.

Now, what accompanies that? Lower risk is accompanied by a lower cost of capital. How is that reflected in rates? Almost all of these commissions in some way or another have talked about lowering return on equity. I actually think that's the inappropriate way to go about it. I think you actually should impute a different capital structure and, in fact, leverage the companies more because the risk is lower. You get to the same place, but you do have a different approach to it, and it does change, you know, as I say, the capital structure. I think that's more appropriate.

But, if the revenue problem is largely resolved, it seems to me that you're giving the utility management an opportunity to really focus on the things that you want them to focus on.

MS. RICHARDS: I mean, I don't want to get into a debate on that.

MR. WESTON: Yeah. Fine, Patty. I'd love to talk about it.

MS. RICHARDS: So revenue stability is a great theme, and, obviously, all utilities, nonprofit and for-profit would like that, but there are some expenses that we don't control, renewable energy credit

market expenses, power market expenses, and those are the things that are giving us heartburn when we don't have that litmus test of control. And how do you deal with that in a not-for-profit model? I get the upside. We get some sort of incentive. But how do you ding a not-for-profit? There's no shareholder to get them.

MR. WESTON: Well, I'm not thinking about dinging them, and you're talking about costs that are generally not included in revenue regulatory mechanisms as all the ones here are.

MS. RICHARDS: So power supply would be the pass-through?

MR. WESTON: Right, and going back to that notion, it could be a pass-through. It's not entirely a pass-through for Green Mountain Power. There's a sharing there, and that might not be the appropriate thing for a not-for-profit. I'm more than open to those, absolutely, those concerns.

But you just reminded me that a fuel adjustment cost is the same as a revenue adjustment surcharge as well. So, to the extent that, to answer your earlier question about Baltimore Gas & Electric, to the extent that folks understand that there will be surcharges and credits associated with changes in power cost, they can understand, I hope, that there will be surcharges and

credits associated with the revenue stability mechanism for the network services.

MS. RICHARDS: Can I ask one last question? Of all the models that you've looked at, are any of them not retail choice states? Most that you put up, I think, are retail choice states.

MR. WESTON: Idaho is not. I don't think -- is Wisconsin? I don't think it is. I don't think Wisconsin is. I'm really out of touch. I don't spend much time here any longer, and that's why I say that I would love to promise -- I'm happy to commit any one of my, my domestic colleagues to come back and chat with you about this.

MS. RICHARDS: Okay, thank you.

MR. WESTON: And, Patty, call me any time, I mean, if you have questions. Any one of you, please, all of you, if you've got questions, I'm more than happy to answer them.

MR. KNAUER: Charlotte, do you have questions?

MS. ANCEL: All set, please.

MR. KNAUER: Riley?

MR. ALLEN: So you've outlined a few of the frameworks throughout the US. Highlighter PIMs, I would assume most of these is PIMs kind of focused

around energy efficiency. Are any of these frameworks using PIMs to go beyond a focus on energy efficiency?

MR. WESTON: Well, yeah. That's what New York definitely wants to do, that's what the UK is going to do, and that's certainly what they're talking about in Maryland, and that's what I think you should be talking about here. I want to -- and service quality, of course, I mean, you've got service quality standards here for all of your utilities, so you've already got at least one element of performance incentives here.

MR. ALLEN: But the incentive portion of it, the financial consequences.

MR. WESTON: Right, financial consequences. I don't know. Here in Vermont are there -- is it just getting -- what happens? Do the utilities and the regulators get angry when the standards aren't met?

MR. YOUNG: Customer compensation.

MR. WESTON: Customer compensation? Okay, right. And there are others.

MR. ALLEN: I just wanted a clarification. You refer to revenue regulation, and I interpret that as decoupling in your presentation.

MR. WESTON: In my lexicon decoupling and revenue regulation are the same thing. I might be more

nuanced and say that revenue regulation is what we're talking about and decoupling is the means of achieving it, and that is by adjusting prices to changes in sales. That's really what's going on here is we're talking about adjusting prices as sales vary from the test year sales that will otherwise produce the authorized revenues or whatever, or I say test year. Whatever the sales number is.

MR. ALLEN: But we're interested in kind of looking at features of regulation kind of going forward that may make sense for Vermont. As you know -- I know you do a lot of work in China -- but Vermont has a separate efficiency utility and delivery mechanism. So, at least as it applies to one of our major utilities, Green Mountain Power, it's not, you know, the energy efficiency isn't necessarily at the centerpiece of this, but I'm trying to understand.

Not to dismiss either. It's important. I understand that. It also relates to net metering and renewables. I'll try to speak more slowly. But I'm trying to understand, and this is really a question for Mark as well, and I'll ask it again at the end.

But what are the features of these plans that, that are, should be viewed as a kind of most important and most valuable from your perspective given the

various dimensions of service and value that are most important to customers, ultimately, but regulators acting on behalf of customers? So here I'm including concerns about capital investment, service quality, price and cost management over time and so on.

MR. WESTON: Well, I think, in certain ways, you've answered your own question, and I'm more than happy to have Mark jump in, you know, through his presentation as well. We sort of split it kind of nicely, because I'm talking about what's, sort of what people are doing now, and he's going to give us a little bit more of a look at the future.

But I'd say this: Energy efficiency isn't the issue for me. It's only one of them, okay? The fact that Efficiency Vermont is delivering efficiency is a great thing or not, whatever. Its, its achievements are affecting the revenues of the utilities. I think revenue regulation helps deal with that. Weather risk, economic factors, all those things are dealt with through, mostly through revenue regulatory means, and I think that's really important because, for me, what matters is, amongst other things, is the economic efficiency of the utility, which I think a regime like this gives very strong incentives for, and it forms the foundation upon which more creative means of regulating

and providing incentives to utilities and others for the outcomes that we want.

Again, it deals with the, the revenues associated with the network, and now our question is, What kinds of products and services are there that we want to, want to see developed? What does that mean for the utility business model? How are they giving -- you know, how do you give incentives for that? Do you? How do you manage all the things that you, I know you're thinking about in the way of distributed resources, two-way traffic on the, on the distribution lines, all those questions?

I, my feeling about it is that this approach gives you a solid, economically sustainable foundation upon which to build those regulatory policies. Not altogether helpful to you, Riley? I'm sorry.

MR. ALLEN: No, no. I'm not -- no, but you're speaking at kind of a conceptual level. I'm wondering if the case studies kind of help to bear that out, if you can't point to debt ratings or other kinds of objective metrics, that kind of help to bring this home a little bit.

MR. WESTON: Oh, it's funny. Yeah. In the case of at least one of these utilities, their debt rating did improve. I can't remember which one. It's

in -- I can find out. I'd have to go deeper into it, and I can get more of that information. Sure, I'll take a look at that sort of thing, yes.

I just want to say one other thing. This is, this is the, the Knute Rockne speech. You have, I think, no idea how much throw weight this state has around the country and around the world. What you do here is watched, and it is highly regarded, and I can point to a number of examples of good ideas that have come out of Vermont that have been adopted around the world and as far away as China. So I really look to you guys, you all, to develop some innovative regulatory tools to, you know, push the vision of the future that I think we all, well, certainly, the, the stated policy of Vermont has or wants having to do with low carbon, greener resources, reliability, low cost. So I guess what I'm saying is, Any way we can help you think about these things, we will, and this is only the start. So with that --

MR. KNAUER: Riley, did you ask --

MR. ALLEN: I'm fine, thanks.

MR. KNAUER: Dave and Eileen.

MR. WESTMAN: Great, thanks. I just want to turn a question towards marginal costs experienced by the customer, and one of the things that I thought was

interesting is your sort of demarcation of essentially decoupling for these sort of short-term fixed costs and then utilities have the obligation to sort of balance the longer term fixed costs.

And so this is something that, as the efficiency provider, you know, we like to go to a customer and essentially get them to support and proceed with an efficiency project on the assumption that, if you make this investment, it will pay for itself over some period of time, and that creates a sort of cost-beneficial scenario for them that they're then willing to sort of take action. Otherwise, if there was no cost benefit to the customer, then the assumption would be that you have to pay a lot more for them to sort of take those energy efficiency actions.

So that's the sort of setup for my question which is that, If, if decoupling will automatically essentially allow a utility to collect on those sort of short-term fixed costs, then the, then what is the incentive for the customer to actually invest in that least-cost resource of efficiency? Because then the utility could come around and actually charge them more in order to recoup their costs.

MR. WESTON: By definition, you're investing in cost-effective energy efficiency. The savings will

be greater than the change in their rates. That's definitionally the case. If it's not the case, then they shouldn't be doing it. So the only question then I think you're really asking is, Are they, is regulatory lag something that would provide a greater benefit to the customer than it is, than it would under a regulatory regime that has some kind of more frequent rate adjustment?

I suppose the answer to that may be yes, but, to the extent that the overall costs of capital to the utility are reduced as a consequence -- and I don't mean just the ROE, but the working capital may be reduced and so on and so forth -- are reduced by the regulatory, the revenue-based regulatory regime, I would think that the difference between collecting the money tomorrow and collecting it a month later is small, or a year later. Remember, we're talking about prudently incurred costs that are just and reasonable. The utility is going to recover those ultimately, no matter what, okay?

Now the question is, What's the best way to do that so that you're actually reducing overall system costs and serving the customer? This is all about serving the customer. You know, I want to be clear that in my mind there's a strong linkage between

revenue stability and cost reduction on the part of the utility and benefits to the consumer. If I didn't think that, I'd be out of here. Your investments in energy efficiency are, by definition, cost effective, so the recovery, the utility cost recovery dimension, the temporal dimension, I think, has a very small impact on the cost, the benefit-cost ratio for the consumer.

MR. KNAUER: Eileen?

MS. SIMOLLARDES: So, if you could, could you give us a little color commentary around that sweet spot that I'm going to call regulatory efficiency and the need to keep your regulators informed with adequate information about what's going on?

MR. WESTON: Yeah, great question. As you, as you see, each of these states does it differently, and the willingness of the state to let the utility go for a longer period of time without intervention is, is, varies. I don't actually have an answer for it. I just don't know. I know that there's been discontent in some states with the frequent attrition adjustments that require, you know, half of a rate case and in other states where the productivity and inflation adjustments which offset each other, and, in effect, in Baltimore's case where there are no adjustments, the

assumption is that productivity and inflation are equal and opposite.

Yeah, I don't have an answer, but I, I think this, and that is the longer period of time that you give the utility under the program without jumping in and essentially taking money back -- and, you know, it's all appropriate. I'm not saying it's not appropriate -- the more incentive it has to, and more flexibility it has to do what it is you want it to do. Now, that also means that your performance incentive mechanisms have to be well designed, and you're going to be tweaking these things all the time anyway, and every one of these plans has been changed in some way or another over the last ten years or eight years or whatever.

I don't have an answer for it. You see that in the UK they think eight years is better than five years, okay? So that's a big deal. I'm not sure anybody in the States would be comfortable with that, but, you know, three years? Gives them a little bit of time. I don't know. But you asked a great question, and I don't know the answer other than my, you've heard my gut on that.

MR. YOUNG: You've spent most of the time talking about the, you know, sort of the revenue model,

revenue regulation. To what extent can you achieve or have states attempted to achieve a lot of the same goals using traditional regulation, you know, and is that, to what degree is that feasible?

MR. WESTON: Many of them probably work. You know, customer service objectives can be met easily with performance mechanisms and traditional regulation. I don't see why not. I think you have trouble with anything on the customer side of the meter. I think that's where your problem really lies, and you're just going to see more of it, you know, more Tesla batteries, right? By the way, I drove a Tesla for the first time this weekend. It was great. Really, it was terrific. If you've never driven one, oh, it was great.

So I think it's -- I mean, anything, if you expect the system to change as we're seeing it becoming a more distributed system, I, I don't see how you, you get the utility, you know, aligned with the customer if it's always worried about its revenues based on sales. That's, I, it just seems really simple to me, I guess.

So there's your conundrum, but a lot of the other ones, certainly, power costs, you can do all kinds of things with power costs that have, that will be unaffected by whether it is a revenue- or a price-based

system, it seems to me.

MR. KNAUER: I have a question. You've, you've noted a few jurisdictions that had PIMs for public policy objectives. Would that cover renewable portfolio standards, meeting the targets in those?

MR. WESTON: It could. I didn't see any in my review over the last few days, but it could.

MR. KNAUER: I'm trying -- I'm struggling with you've got, you know, an annual target, and, if you don't meet it through procured RECs or something, then you have an alternative compliance payment, so you're supposed to be doing it anyway.

MR. WESTON: Right. Well, that would be a PIM of its own sort then, the alternative compliance payment. That's right. I had forgotten about that.

MR. KNAUER: Yeah. I was struggling to think if there was, you know, financial benefits to the utility for meeting the RPS.

MR. WESTON: I hadn't seen that. I hadn't seen it.

MR. KNAUER: Other questions for Rick? Mr. Lowry?

MR. LOWRY: I do have a question because I think it will help the transition to my presentation. So, when you talk about revenue regulation and which

involves revenue decoupling, now, there are a few states where they actually don't give any escalation at all to the revenue.

MR. WESTON: Baltimore.

MR. LOWRY: Well, they have their per customer.

MR. WESTON: Oh, the per customer change, yeah, right.

MR. LOWRY: And so you must -- I think you're meaning that there is some automatic revenue escalation, and could you clarify what you had in mind for that?

MR. WESTON: Well, what we've seen -- and, again, these correlations are not, you know, really high, but what we've seen is that, in the short run, nonpower costs vary more closely with changes in numbers of customers than they do with changes in usage. That would make sense. So it has to do with all the customer service and marketing costs that you incur for adding or dropping customers.

So the idea with the RPC model is essentially mathematically it works this way: You've got your total allowed revenues. You do your rate case, and you've got your authorized revenues. You divide by the number of customers, and you get an average revenue per

customer, and you can do it by, and you probably would do it by customer cost, okay?

A year from now, and you'd have some sort of mechanism for determining -- you know, you'd want to average it across the year -- but just to simplify it for these purposes, a year from now you're going to take a look at your number of customers, the actual number of customers, and you're going to multiply that number times your average cost per customer, average revenue per customer, and assuming as, for the purposes of this exercise, that your customers, the number of customers have gone up, which is certainly the case in the southwest every year, then your authorized revenue for the next year will be higher.

So, if it's, you know, we got 100,000 customers at $1,000 on average, whatever that is -- is that a -- I can't do the math. Is that $10 million? Well, then, if we have 105,000 customers, it would be that much more money in the next year, and that would be the, an adjustment to the revenue.

Oh, and by the way, a lot of these programs refer to adjustments, the overall scheme of adjustments as the revenue adjustment mechanism. So you'll see, you'll see the acronym RAM for amongst other things. I hope I've set you up well.

MR. LOWRY: That helps.

MR. WESTON: Good.

MR. KNAUER: All right. Thank you, Mr. Weston. We will have a technical break to get Mr. Lowry's presentation up on the screen. Mr. Lowry is the President of Pacific Economics Group, and I believe he is here today made possible by Green Mountain Power. So we'll take a five-minute break.

(A recess was taken from 2:34 p.m. to 2:41 p.m.)

MR. KNAUER: Okay. We're going to get started again. Back to the presentation that's on the screen. So I will reintroduce Dr. Lowry. He is the president of Pacific Economics Group, and he's been brought here today by Green Mountain Power. The floor is yours, Dr. Lowry.

MR. LOWRY: Thank you very much. It's a real pleasure to be here on such a beautiful fall day. I've always wanted to see these mountains when the trees are starting to turn. Really getting red up at the higher elevations, and so you can see it. It's also very nice to be in this lovely old state capitol. I live in Madison, Wisconsin, and I like to think we have the best state capitol, but it really is gorgeous if you ever get a chance to see ours. Also exciting to share in all the excitement the day after the Lake Monsters's

big victory over Mahoning Valley, so congrats to all the guys in the room for that.

So what brings us here today is really this period of rapid change that the electric utility industry is experiencing, and the whole idea of performance-based regulation and other alternatives to traditional cost-of-service regulation is to deal with those changes more effectively, and what I'd like to do in today's presentation is take about an hour to talk about PBR and some of the other options that are being tried by regulators around the country to talk about some of the key precedents and recent developments.

I recently wrote the second paper for, on PBR, for Lawrence Berkeley National Laboratory. I wanted to share with you some of the results from that and, just generally, kind of emphasize the utility of the future themes inasmuch as this state, as much as any, is interested in all this nexus of activity around renewables and distributed generation and the like.

So we're going to start by talking about how cost-of-service regulation stacks up as a way to address all the changes in the industry today, and then we are going to start to talk about some of the alternatives that are used by regulators around the country, and then we're going to go to talking for most

of the presentation about the performance-based regulation approaches to addressing these challenges, some of which were addressed by Mr. Weston.

So what do we mean when we talk about cost-of-service regulation? Almost everybody in this room has a pretty good idea about that. We're talking about base rates, rates for capital and labor, materials and services are going to be adjusted periodically in general rate cases. There's typically a tracker or rider mechanism for the energy costs. As I understand it, that wasn't traditionally part of Vermont regulation.

We're also talking about legacy rate designs that are sometimes called in which usage charges collect many of the so-called fixed costs, costs that are insensitive in the short run with respect to system use. What I talk about in this new paper for Berkeley Lab is a fundamental attribute of cost-of-service regulation that how well it works depends an awful lot on external business conditions that utilities face.

When the conditions are favorable to utilities, then, hey, it works pretty well because rate cases are infrequent. They don't come in for rate cases very often, and that, in turn, strengthens their performance incentives. So that's when cost-of-service regulation

is at its best.

Now, at the alternative, supposing that regulation it chronically unfavorable. Well, then everything is in reverse. Rate cases are frequent. Performance incentives are weak. Also, the operating flexibility of the utility is more likely to be restricted because it's such a headache to deal with it in those rate cases.

So a funny implication of this is that one thing about cost-of-service regulation is that the worse things get, the worse the business conditions get, the worse the utility performs instead of the best the utility could perform, and that's just the opposite of how things work in a competitive market where, if you have a downturn in the price for your product, you know, you're going to redouble your efforts to cut your costs. You're going to keep your prices down. Utilities are more likely to raise their prices when things are going badly under cost-of-service regulation.

Now, in the Berkeley Lab paper, I provide some evidence of this whole issue of external business conditions and how it can affect the behavior of utilities. I note -- first of all, what I did is I tabulated key measures of financial attrition of

utilities between rate cases, and one is the average use, which gets into this whole issue of the gravy you get from growth in system use when your cost isn't really growing with it. So you want to have growth in average use. You sure don't want to have a decline in average use. And then the other thing on the table is the price inflation as represented here by the gross domestic product price index inflation, okay?

So what we find and why these numbers are in yellow is that there was this period before about 1973 when the business conditions facing the utility industry were remarkably favorable. There was rapid growth in average use. Today we're talking about decline in average use. So maybe, for example, a residential customer it might be .5 percent a year or 1 percent a year. Well, it used to grow by 5 percent. We're not talking about .5. We're talking about 5 percent a year. So this was a tremendously help to the utilities to self-finance their own cost growth.

Then the other thing was that inflation was usually pretty good in those days, too, excepting during the two wars, World War II and the Korean War. So this is what I like to call the Golden Age of Utility Regulation, when this attrition indicator that I developed actually incurred negative values.

Now, that was immediately followed by a period when things were really bad and, because of two oil price shocks, inflation grew substantially very high, hyperinflation in the 70's, and then also it didn't help that energy prices in particular were going up, and that was a big part of the utilities' costs, and so their costs were really rising fast, and so demand starts to slow and, in fact, has never recovered from the impetus of the rising relative prices of gas and electricity -- in this case, we're just looking at electricity -- during those years.

Now, since then things are better because you'll notice that inflation is down a lot from the old days, from those really bad days, and average use actually has continued to get slower and slower. So things are better than they were, but it's, the major point here is that business conditions today are, like, way worse than they were in the Golden Age of COSR when COSR became a tradition. Not only that, they're actually at the worst that they've been for since this really bad period that ended in 1986 when oil prices finally collapsed, because average use has actually gone negative for residential and commercial customers.

And consumer advocates like to point out -- and it's true -- that inflation is also slowing. Now,

that's absolutely true. So the situation could be worse. Inflation has helped to offset this very dramatic deterioration in average use from the Golden Age of COSR, but, you know, the problem is is that inflation is, there's a very good chance it's going to start to accelerate.

It's as low as it can get, and, although economists have been stroking their beards a lot about this lately as to why, with an improving world economy, that there isn't more inflation. There's an article in the "Wall Street Journal" about that in just the last few days. But, at any rate, they're bound to go up from here, and, when that happens, you're going to be in even more deterioration in that number than you have now.

Now, incidentally, how did the productivity or how did the performance of the electric utility industry do during that period when business conditions were really bad? Well, you can see from this chart what the federal government did for many years. They measured the multifactor productivity trend of the electric, gas, and sanitary sector of the economy. It's mostly dominated by electric utilities, but, to the extent that it's also dominated by gas utilities, they had similar problems to the electric utilities in those

days, and what you can see is that, during the Golden Age of COSR when business conditions were favorable, productivity growth was really great, keeping the price of electricity growing more slowly than general prices.

The productivity growth of the industry has exceeded that of the economy, but, during this period when the rate cases were frequent, there was actual termination of growth in the productivity of the electric utility industry. For many years it was worse than the productivity growth of the economy. So this is a nice example of the importance of incentives. In a period of great incentive environment, productivity was great. Period of bad incentive environment, much, much less great. In fact, in my opinion, this was part of the reason for the eventual restructuring of about half of the US electric power industry was poor performance that took place during those years.

Now, those aren't the only two slides of attrition. Another one is capital spending, particularly capital spending that doesn't automatically trigger revenue growth, and the capital spending outlook of utilities varies across the country. You know, sometimes, you know, you expect someone to get up and he's talking about what's going on in regulation today as if there was one utility

industry. Well, the complicated thing is, no, we have different parts of the utility industry that have different economics.

For the UDCs a lot of them today claim the need for sustained, high nonrevenue-producing Capex to do things like system modernization. Some of it's smart grid, but a lot of it's accelerated replacement spending. Five, ten years ago they weren't doing that. All of a sudden, they say they need accelerated replacement spending. Okay. Sometimes there's more interest in hardening the distribution systems against the severe storms.

So the upshot of this is that many UDCs need larger and more frequent rate cases than they did in the past, and this can kind of throw a regulatory commission for a loop because they, they don't have the same kind of experience with a claim of a need for accelerated modernization as maybe in the old days they did, finally mastering the art of deciding whether you need a generator plant and, if so, what technology to use.

They got to be good at that, but this whole idea of accelerated modernization is something they're really scratching their heads about, and this has led to a lot of interest in distribution system planning.

NECPUC is having a conference on that in just a few weeks' time in Hallowell, Maine. I happen to be a speaker at the conference.

Now, whole different situation with the Berkeley integrated utilities. This whole thing about slow demand growth has meant they don't need to build as many generators as they used to. Not only that, generation technology has changed, and the lower price options now are wind and gas-fired units, and so they don't need to build as much generation, and the generation they do need tends to be smaller, more modular and predictable of when it's actually going to come online. Not only that, but, to the extent that they have older generating plants, that stuff is depreciating, and, as it does, it slows their cost growth, something there's no quite a parallel for with the power distributors.

And, besides, if they need any distribution Capex because, potentially, some of them also need to accelerate their modernization, it doesn't matter as much because the generation sector is a third, at least, of their cost. So the VIEUs today are experiencing slower and steadier cost growth, and it's more predictable and is easier for parties to agree to a potential multiyear rate plan type of mechanism than

in the past.

So, basically, with cost-of-service regulation today, it's, it's a situation where the utility is typically going to be in every two to three years so there aren't very strong performance incentives. Really, rate-based growth is the main path to earnings growth for utilities. Regulators are going to tend to discourage marketing flexibility, and, also, this really limits the amount of time people in the regulatory arena have to worry about more important issues.

There are so many interesting generic issues going on, rate designs, review of multiyear rate plans. I mean, people could be focusing if their time is better served, instead of just another rate case, something I like to call Groundhog's Day regulation, better served focusing on these, you know, What's the right rate design for Green Mountain Power, for example, than just another rate increase.

Now, another thing that, and it's been mentioned during the last time you guys got together for your workshop, is that it's pretty well known that COSR doesn't do a great job of incentivizing utilities to embrace demand-side management and distributed generation and storage values, the acronym DGS. You

looked like a group that needed another acronym.

So we all know the problem with so-called throughput incentive that declining average use reduces sales between rate cases, but the other two points are not as widely recognized, and one is that rate designs that do encourage efficient DSM and DGS are risky in their own rights. Let's say a lot of your base revenue is riding on peak, peak period charge. Well, it could be more sensitive to weather conditions, and you don't know how much customers are going to migrate away from use of the system peak because everybody is on a time-sensitive pricing.

Another thing that's not emphasized enough is that many load-related costs of electric utilities are tracked, and, in addition to the cost of energy, it's tracked so that they're largely indifferent to how much of it they use. Nowadays, most of their transmission costs are tracked, too, through their formula rates at the FERC, and then lots of times they track those at the state level as well. So they don't have a very good incentive to contain the cost of transmission which is very well known to be a function of peak system use.

All right. So it's, so our cost-of-service regulation incentivizes utilities, frankly, to resist,

to oppose DSM and DGS. So over the years they've thought of all these ways to sort of drive utilities to be more accepting of them, and there are a lot of things, a lot of work has been done on that on the DSM side to the point where you don't hear utilities complaining a lot about DSM anymore.

Now, there hasn't been as much work to make utilities embrace efficient DGS, and I'll just ask. Have you noticed a difference in the attitude of the typical American electric utility towards distributed generation than to DSM? The lack of incentives has meant that they have taken, done exactly what the regulatory theory is and actively resisted DGS.

I'm not going to read the statement, but I just want to say -- and this is the start of a memo -- emphasize repeatedly that I'm not the only person saying these things, and regulatory pundits aren't the only person saying these things. A lot of regulators realize these flaws and limitations of traditional regulation that it has weak performance incentives and that it has high regulatory costs.

And what makes, part of what makes this statement from the Alberta Utilities Commission interesting is that they've been dealing with a whole bunch of gas and electric power distributors that have been coming in

for rate cases every two years, as often as they could, and then each filing had two forward test years. So they were just in for rate cases all the time. Their rates were growing like crazy, and they just said, We want to try something different. Incidentally, the Chairman of the Commission was a former telecommunications industry vice president. So they, they ultimately decided to go to a multiyear rate plan in the form of regulation mandatory for the states' and provinces' utilities.

So, as we start down the road to these talking about alternatives, you basically want, utilities are going to want to sort of nick away at these problems of attrition between rate cases with the hopeful outcome that their rate cases wouldn't be needed quite so frequently, and the things that they propose, and not just the utilities, but other parties have proposed can be grouped into targeted adjustments and comprehensive adjustments. So, for example, cost trackers would just be sort of a band-aid sort of approach where, if you have one cost that happens to be growing faster than, particularly faster or it also could be volatile, then you could ask for a tracker for that.

Revenue decoupling was mentioned and emphasized a lot by the prior speaker, and when it gets to the point

where average use is actually declining, a lot of utilities are going to ask for that to be addressed surgically by decoupling or by some other means. And then there are these targeted performance incentive mechanisms that are PIMs that he also mentioned.

Now, then there are also more sweeping changes, bigger ticket items like integrated distribution planning, the topic of this NECPUC conference that's coming up; formula rate plans which is sort of a form of a broad-based cost tracker where all costs basically flow through a tracker; and then the multiyear rate plan or MRP approach that we'll be talking about quite a lot today.

So let's talk a little bit about what's popular amongst these options. That was one of the things that you wanted this presentation to be about. Well, the capital cost tracker approach is very popular. It's been used all over the country, gas and electric. Just a few holdout states, and utilities are often very good at coming up with, We have this particular cost pressure. We'd like a tracker for it. Commissions have been pretty open to this, and you'll notice that we're talking here about the capital cost trackers, and so a lot of companies have been able to get those.

One thing that I thought would be interesting to

point out the ones that had comprehensive cost trackers, because that's not so different from what GMP has today, because they have sort of expedited annual rate cases for capital costs a little bit like, a little bit, just a little bit more demanding filing requirements than -- and so, actually, the two states where you do see this, Ohio has been one. A lot of the power distributors in Ohio have a tracker for all capital costs, and then Massachusetts, one example, but it's a big one, is National Grid in Massachusetts has had this for a while.

Revenue decoupling, as we mentioned, and, incidentally, I'm a big fan of revenue decoupling, so I agree with much of what the prior speaker, Mr. Weston, had to say about that. You can see that in the gas industry it's been very popular, and the reason for that is that they're the ones that had the declining average use, they've had it for years, and so they wanted to remedy this one problem that would permit them to come in for rate cases less frequently and reduce their risk, various benefits, and so that's been very successful. There's one region of the country where you don't see a lot of them in particular, and that's because they have another remedy that I'll talk about in just a minute.

Now, if you go to electric, you'll find that they're not as popular as on the gas side. Don't forget that a lot of utilities have LRAMs instead of the decoupling approach. You'll notice, too, that, boy, it almost looks like an Obama election map or something in terms of the states that have the decoupling, and, really, it has something to do with the fact that, Idaho being a large exception, that these are states that really care about conservation a lot, and that tends to go along with approving revenue decoupling.

Now, I had mentioned about the southeast that they had a different way of doing things in the southeast, and that's what we call a formula rate plan. Not all the utilities have it, but many of them do. It's more the more typical approach. You'll note, though, that it's a lot more popular for the gas companies than it is for the electric utilities, and the reason for that is that this is an approach to that declining average use issue which they found that they were comfortable with in the southeastern states, and so it's tended to spread over time from the original states to places like South Carolina and Oklahoma. It's also noteworthy, though, that this, this approach with the big cost tracker which would tend to weaken utility

performance incentives, generally speaking, is not that popular across the country.

So now we're going to start talking about the performance-based regulation, and they're really, when I talk about performance-based regulation, I just mean, generally speaking, an approach to regulation that encourages utilities to perform better and then hopefully share the benefits in some reasonable manner between the utility and the customers.

So there are basically three main approaches to the PBR, and one is these targeted PIMs that, that Mr. Weston talked about. There are the multiyear rate plans. We're going to talk about those a lot. And we could also throw in incentivized cost trackers, which we're not going to talk about further today, but, strictly speaking, incentivized cost trackers by, for example, you know, you have a target cost, and then, when you go to correct for the deviation of the actual of the target, you knock off 10 percent or something like that. That's, those, that sort of thing has been around for years.

So let's start by talking about the PIMs and just more broadly about performance metrics. A metric is a variable that, that can quantify a dimension of performance that matters to the regulator and the

customer, and you can use those metrics in several ways. You can just monitor the darn things, or sometimes you can add a target for it without penalizing the utility if they deviate from the target or reward it if it does a better job.

What a PIM is is when you do have a mechanistic relationship between their earnings and their performance as measured by some sort of a target. So I like to use the word performance metric system because, in the modern day utility and the utility of the future, you're going to see a lot of metrics, but they aren't all going to have a PIM attached to them. Maybe most of them won't. There will be some things that commissions just want to monitor. There are some things they want to add a target, and then there will be a few that they want to have a PIM for.

And so and the next step in the process is to go to a scorecard where you put how the company is doing with respect to a bunch of these metrics, not all, again, not all of which have a PIM, and then maybe you put the, post it on the website of the Commission to kind of put the utility on the spot, and it's an incentive for the utility to come off well.

And here's an example of one of these that comes from the Province of Ontario. Ontario is more or less

the most advanced practitioner of PBR in North America today, and so here you see a whole welter of metrics, service quality, customer satisfaction, safety, reliability, some cost control items, connections of renewable generation, PBR or DSM types of metrics.

So and, not only do they have the metrics, but they're taking stock of how the utility is doing, and they're posting it on the website of the Commission. So there's, in Ontario there's, like, 70 of these power distributors, many of them municipals, by the way. And so it just an interesting -- you should -- I would encourage you to take a look at that website sometime if you haven't seen it before.

So the rationale for these PIMs is to strengthen utility incentives in particular areas where they're weak. The traditional focus and, really, by far the vast majority of them in the old days were just for reliability and customer service quality, because they were attached to these multiyear rate plans that were strengthening incentives for cost containment, and they didn't want them to let their service quality slide, so and that's the beginning of another story about how most them, the commissions that are the leaders in developing new PIMs also are leaders in multiyear rate plans. It's not sort of a one-or-the-other thing.

The other thing that's really popular today is energy conservation PIMs. Most, I won't say most. About half of all of the states in the US have some sort of PIMs for energy conservation, and, in fact, Efficiency Vermont has some sort of a reward mechanism of its own with the State or with the Commission.

MR. WESTMAN: With the Commission.

MR. LOWRY: With the Commission? So you have it here, only you're not a utility. All right. Now, as people look to the future, they start thinking of all these new kinds of PIMs that are going to be needed to address emerging utility challenges. Frankly, it's become kind of a cottage industry to think of these new PIMs, and some of these were alluded to by the prior speaker.

The things that people talk about the most in terms of these new PIMs to address new challenges would be in the areas of peak load management, and that's partly based on the data that they already had some sort of a conservation PIM, but then also just utilization of the AMI capabilities. Have you got AMI? Well, how many people are using your web portal? How many people are signed up for time-of-use rates, and that sort of question. By the way, do they work well? And then another whole thing is that quality of service

to the DGS customers, interconnection times, and you noticed that there was a list of metrics of that sort in the Hydro Ottawa scorecard that I showed you.

Now, just a little bit more about this peak load management thing. One way that you could approach the peak load management is to somehow have some kind of a measure of system load peakedness that you reward the utility for reducing. Sometimes, though, it's not a system thing. It is more of a local thing where, where there's a particular area where some sort of a load-related cost could be avoided by having a concentrated use of DSM and DGS, and they, these kinds of programs go by the sobriquet of non-wire alternatives or NWAs.

That's the term they use in New York, and Brooklyn-Queens Demand Management Project is probably the best known example of this. It's a gentrifying neighborhood on the border of Brooklyn and Queens. I think the Gowanus Canal is there, and, you know, it's kind of a cool place to live, and so they've had to thinking about over a billion dollars of upgrades to the distribution and subtransmission system in order to serve this area, but they resolved to try to avoid that or at least postpone the investment using intensive DSM and maybe some DGS. That's meant to be DGS there.

So, again, where you see the guys that are in the forefront of this, they're usually also the guys that do the multiyear rate plans. California, Minnesota, New York, and Britain all have multiyear rate plans, Minnesota being a newcomer to it, but Britain has been operating under multiyear rate plans since the 1980's.

So let's talk about what we mean by a multiyear rate plan. We're talking fundamentally about a regulatory system that has a rate case moratorium, typically a three- to five-year rate case cycle. It could be as long as ten. There was a mention of the eight-year cycles in Britain, but we've actually had ten-year plans here in the United States, both of them actually involving National Grid.

There's also -- so what happens between those rate cases? Because cost is going to tend to rise, so you need to have some kind of way to raise rates or revenue between the rate cases, and that's trying to be done by -- they try to do this as much as possible with an attrition relief mechanism, they call that, or an ARM. It's what the prior discussant called a, a RAM, a revenue adjustment mechanism. He was assuming that there was revenue caps, but, see, I can't assume that, and sometimes people have price caps.

So I'll call it attrition relief mechanism.

That's a California term, and what's key with it, though, is that you get some revenue escalation without basing it on the company's own cost. So it's a little bit more like a competitive market. I mean, in the competitive market in the jet industry, the airline industry, you know, prices will drift upwards with jet fuel prices, general price inflation. There is some addressing of changing external business conditions, but it isn't specific to any one utility's cost.

Now, that isn't to say that there aren't any trackers with the multiyear rate plan because, truth be told, it's kind of hard to develop ARMs for all the volatility in, like, the northeast energy market. So something like that is going to be addressed by a cost tracker, and, of course, there's going to be some sort of a performance metric system that, at a minimum, is going to include those service quality PIMs to avoid incentives to let the quality slide.

Now, there are all sorts of bells and whistles that you can add to one of these things. Revenue to the company is really easy to add, and, generally speaking, I'm a fan of revenue to the company as the past speaker is. Earning sharing mechanisms, we already have that with the alt. reg. plan of GMP. Some marketing flexibility provisions, again, you

already have that with GMP. Some additional PIMs, the most common thing is to have the one for conservation. You probably don't need that for GMP because that is done by another agency.

And then there is a fancy thing called an efficiency carryover mechanism. I'm not going to get into how that works today. I like to call that MRPs 301. But, basically, the idea is to reward the utility for long-term performance gains when they come in for the next rate case, and, if you come in for the next rate case and say, Hey, it's time for the customer to get part of their share of the benefits, well, if they actually get some benefits at that point, then the utility gets rewarded, and that's supposed to incentivize them to achieve long-term efficiency gains.

So the rationales for MRPs, one is for sure streamlining regulation. I mean, if you're going to have a rate case only every three, four, five years, that's for sure reducing, avoiding a very expensive part of the regulatory process, and, not only that, but you can decide in advance when the rate cases are going to be so you can stagger them so that there are fewer and less overlapping rate cases and, again, people are freed up to go do something else in the regulatory. It doesn't mean people are getting laid off. It just

means that you have more time to devote to important generic issues, for example.

Other benefits of MRPs include strong performance incentives. It's a well-designed plan. There could potentially be more operating flexibility because, if the utility is kind of on its own on a rate trajectory or a revenue trajectory for a few years that has no feedback link to its own actions, then it better do the right thing, and it will tend to reduce the regulator's concern about them engaging in prudent behavior.

The other thing about an MRP in the short sales pitch is this area of demand-side management. Lots of times they talked about the three-legged stool, that's what the AC triple E talks about, three-legged stool that supports energy conservation, and it would be, first of all, tracking the utility's DSM expenses -- that's not an issue for GMP -- revenue decoupling, and then some sort of an extra so-called positive incentive in the form of a DSM performance incentive mechanism.

The part that people don't understand is that, if you're under an MRP, you already have this built-in incentive to contain your costs. So, hey, how about using DSM in order to help contain your load-related costs? There are a lot of stories about that in other industries.

Like, the railroad industry was one of the first to go under a multiyear rate plan, and so what they did is they used, you know, they, for example, they offered discounts for, you know, coal mines to develop their own unit trains, Put your own train together, or they told the grain, you know, silos that, If you just put your silo along the track line, we'll offer you a nice discount for that. So they got them to make less costly demands on the utility.

Marketing flexibility is an area that, well, it's worth mentioning here because GMP already has some, but the basic idea being that, if you have fewer rate cases, there are fewer opportunities for cross-subsidization. You're not going to have to be wracking your brain about the fact that the utility has seven green power options instead of three because, between rate cases, it doesn't matter as much, and what usually comes out of it is some sort of a light-handed regulation of optional tariffs and services and special contracts.

So you could have special contracts for large load customers, and you could have more flexibility to offer green power packages and energy transformation services and reliability differentiated services and other smart grid enabled services.

Something they always talk about in those New York REV proceedings is how this is going to be a big new source of revenue for the utilities, but what I think is, Well, how is that going to work if you didn't have infrequent rate cases? Because the margins from those would flow immediately back to the customer as another operating revenue. But, if you have a multiyear rate plan, they can keep that for a little while, and it gives them more incentive to build up those practices.

Indeed, MRPs have been particularly popular in industries where you didn't need marketing flexibility like railroads and telecom where there were complex changing customer needs and technological change. Remember when things like caller ID came into service, became a possibility, and, you know, those types of, those types of services were typically offered under the terms of marketing flexibility. That included what you have here in the state of Vermont.

So, when you look at the precedents for multiyear rate plans, there are a lot more of them than there is revenue decoupling. It's actually one of the more increasingly popular alternatives to traditional cost-of-service regulation. Interestingly enough, a lot of the growth in these MRPs has been with the vertically integrated utilities and not so much with

the UDCs, the utility distribution companies.

The original jurisdictions to work with MRPs were California, Massachusetts, and Maine. You notice that Massachusetts and Maine don't even have an MRP anymore. California does. New York was the other big one. But then you look at all these states that don't have, that have utility distribution companies that don't have MRPs, and I'll be willing to explain why that is.

A lot of people also don't realize how popular MRPs are in Canada. Basically, in all the populous provinces of Canada, they have, they're more or less mandatory now for, at least for gas and electric power distributors, and there are a couple of other interesting stories about that. In general, the impetus for the MRPs in Canada does not come from the utilities. It came from the regulators or from higher level policy makers.

In fact, when the first MRP was established in Alberta I was talking about earlier, the utilities were so unhappy with it that they took the Commission to court. In Ontario an interesting story, they had a lot of impetus to go to the MRP because they suddenly had the responsibility to regulate, like, 70 companies, so an economical approach to regulation was very appealing to them. Now, when I say 70 companies, about 60 of

those are munis, so, just, I know that in the last meeting that all the munis here were saying, We're not interested in that MRP stuff, and that's fine. They may have their reasons. But just saying that in Ontario all the munis are, pretty much, all the munis are subject to this form of regulation.

Another interesting story right north of here in Quebec, okay, so Quebec had a law that said you have to have PBR. You have to have a form of regulation that achieves continuous performance improvements, shares benefits with customers, and streamlines regulation. So they've had a proceeding going on up there for about two years as to, Well, how do we do this for the power transmission and for power distribution? Editor's note, the production was already subject to a sort of a PBR scheme.

And so the utility Hydro-Quebec was very, very conservative, and they really just wanted a little baby step in the direction of an MRP. They were not -- they really didn't have the -- they really didn't want it, but it was the consumer advocates who strongly advocated, not only going to an MRP, but going to a rather radical approach that involved an index-based escalation formula, no cost trackers, and the Commission ruled in favor of the consumers, and now the

company has been ordered to operate under an MRP with an index-based revenue cap.

Now, I want to talk a little bit about this area of ARM design, because, if you ever get serious about doing this in Vermont, this is going to be the biggest issue. This is the hardest thing to agree on. This is where most of the money is riding on. So let's just talk a little bit about it and get the wheels turning that there are four well-established approaches to this.

One is indexing, which is basically escalation to, that's linked to external business conditions like customer growth and inflation. A forecasting approach where, basically, you say, Well, you know, the utility forecasts our costs over the next four years. You can have a hybrid where you have maybe indexing for O&M expenses and some other way of addressing capital costs. So you can break the pieces of cost up into different, different, give them different rate-making treatments. And then there's a tracker/freeze approach that I'll discuss in a little bit, which I also think is of some interest here in Vermont.

So there's no really one right approach. It all depends on the nature of the utility and on the regulatory traditions in the jurisdiction. To give you

an idea of how differently it can all go, let's take a look at power distributors first, and remember that GMP is sort of a hybrid between a vertically integrated utility and a UDC because they don't have a lot of generation, a lot of transmission from in their own company either.

So the, it used to be that those index-based approaches made sense for the power distributors, and that's what they would propose, because their costs tended to grow really gradually as the, as the service territory expanded and you're serving a new subdivision here and a new strip mall here. So, typically, their cost growth tends to be gradual.

But what happens if the utility claims the need for accelerated modernization? Well, now you're going to be on a ramp like this, and this is exactly where so many of these northeast regulatory commissions find themselves, utilities that say, We're here, and that's -- and, when you're not even sure about the need for that much revenue escalation, you, you know, it may not be the best time for you to embrace a multiyear rate plan.

So this has slowed the adoption of MRPs by UDCs in the United States beyond the original innovating groups, but Canadian regulators are different. First

of all, there might be a law that says you have to do it, but, at any rate, they're hell bent on doing multiyear rate plans, even though there's accelerated modernization in some cases, and so they've experimented with various approaches. I can't say that it's always been successful or that they have figured it all out, but they are making progress, and anyone who's really interested in the topic, you know, proceedings in Alberta and in Ontario are great places to look because they're grappling with these issues.

Now, meanwhile, what used to be the typical rate escalation trajectory of an electric utility, a vertically integrated utility, a big sort of rate shock, rate increase when a new solid fuel power plant or a big hydro plant or something comes online, and then the depreciation from that plant slows the cost growth for a number of years, and then they go up again, and it's always hard to tell when that plant's going to be finished, and so it's very hard to develop -- it seems very hard to develop a multiyear rate plan.

But now what you have is more of these little, much, much smaller and more frequent stair steps when maybe they add a new combined cycle unit or something to their system, and so it's a lot easier for the parties to regulation to identify adjusting reasonable

ARM for a vertically integrated utility today, and that's why I think that they are more popular at the moment with the vertically integrated utilities.

Now, one of the things I do in the case study is to look at how has this actually worked where it's been implemented because very few people have ever done that. So I thought one of the interesting case studies for you is Central Maine Power because it's a neighboring state. It's just a few mountain ranges to the east, and they've operated under three generations of these multiyear rate plans, and, again, the impetus for this came from the Commission, not from the utility.

It was, they had a chairman there who was a former telecommunications industry lawyer. I think he worked for NYNEX, and so he said, We're going to do multiyear rate plans in Maine, and it's just a question of what kind. Well, if the Commission says that, then everyone's going to propose their own approach, and even an ARP proposed their own approach to multiyear rate plan in Maine.

And this is the details of the third-generation plan. It has one of these index-based attrition relief mechanisms. It did have a capital cost tracker for AMI. Did have earnings sharing, although it was

asymmetric and it only shared the surpluses, a five-year term, and it had a lot of marketing flexibility because, at the outset, it was a vertically integrated utility with a lot of pulp and paper customers, some of which were economically marginal and whether or not they were, they could generate, use some of their byproducts to make their own power, so they really needed a lot of flexibility to keep those guys from leaving the system.

Well, how did they do under this MRP? Which they called an ARP, by the way, alternative rate plan. In this paper what I do is I look at lots of examples of the trends in the power distributor productivity of the utilities, compare those under MRPs with those that didn't have MRPs, and, when I say power distributor services, I mean customer services as well as the distribution services.

So this is a period they were under PBR, and you can see that their multifactor productivity growth was well in excess of that, of the upper northeastern utilities and even better than mid-Atlantic utilities because there is an interesting story there because a lot of mid-Atlantic utilities stayed out of rate cases for over a decade. In fact, there's one down there that has never come in for a rate case since the

1980's, that being Potomac Edison, another story that rarely gets told enough.

Here's quickly just an example of one, of a plan in California, typical California plan. Now, here you've got more of a hybrid mechanism for setting the rates and the revenue escalation because it does have revenue decoupling, and you'll notice that they break it out separately for generation and distribution. So there's an idea that possibly could work or make sense in Vermont. It might be appropriate to have separate rate-making treatment for those two.

And it, they, with their revenue decoupling and their multiyear rate plan, also were very much national leaders in rate designs that encouraged demand-side management. In their case, these were rather extreme inverted block rates for many years, and now they're also a leader, and they keep moving in the direction of mandatory time-of-use pricing for residential and small business customers.

I mentioned the tracker/freeze approach, and I'm just going to come back to it for a minute because this is another idea that might be of some interest here, and the idea here is that, if you could just address one or two rapidly growing costs by a tracker, then you could freeze rates on everything else, or maybe it

could be revenue per customer and you could have decoupling. But, at any rate, you have sort of a freeze on everything except for the rapidly growing cost, and the cost that usually is designated for tracking is the cost of new generation capacity, and I think that this is, this is the approach that's been used by a lot of the biggest electric utilities in the United States.

A law was passed in Virginia mandating this approach to regulation for both of the Virginia electric utilities. So, just, these are just all ideas that, that all could be considered in the design of a plan for GMP, and here's a, here's a real world example of that, Arizona Public Service. Interesting, by the way, how many of the companies that are subject, that have accepted the most penetration of distributed generation and storage are also MRP jurisdictions like Arizona, California, and Hawaii. They all have multiyear rate plans.

So, at any rate, in this particular case you can see that there was provision for extra money if they acquired a couple of coal-fired units in the Four Corners region. Apart from that, it was basically a rate freeze, so that's what we call a tracker/freeze. Almost done. Getting towards the end.

We talked a little bit about incentive power research, something I've been doing for many years, partly funded by regulators, partly funded by utilities, and the idea is to simulate, use numerical analysis to simulate a rational utility response, so a sort of stylized regulatory system but one that sort of gets to the essence of a real world regulatory system today. So we can look, for example, at the impact of multiyear rate plans or, What if you add an efficiency carryover mechanism?

And so there are a lot of interesting lessons that come out of this, and one is that definitely multiyear rate plans can improve cost performance. It wouldn't be all surprising in a well-designed plan that after ten years the utility's cost would be 10 percent lower than it would be if it stayed under cost-of-service regulations, for example. It's also the case that the real benefits depend on what the alternative is. I mean, if you, if the utility is only coming in for a rate case every three or four years, well, the extra benefit of going to the MRP isn't going to be that great, but, if they're coming in for a rate case every one year or every two years, then the benefits are more substantial.

Another thing to note is that lots of times the

first time you do PBR it's a transitional mechanism with a lot of -- it's sort of like bumper bowling so that nothing can really go very wrong, and sometimes those approaches don't really have much of a magical performance impact, but maybe they're a necessary first step to getting to a better plan in the future.

So a first glimpse of what I think the utility of the future is going to tend to look like. You might say this is more what seems like will be best practice in regulating the utility of the future, but I think you're going to see it in a lot of places. You would combine a multiyear rate plan with revenue decoupling. There would be PIMs for things like peak load management, but here it's distributed energy resources. There would be time-sensitive rates. In all likelihood, integrative resource planning would extend to the distribution sector, and, if the VIEU, if the company is vertically integrated, it probably will have a pretty large role in renewable generation.

So my last slide, and then I'll entertain comments, is that I think, you know, regulation in Vermont should be efficient. It should be mindful to strengthen utility performance incentives, share benefits with customers, and it's important right now in an age of mounting reliance on intermittent

renewables that it encourage efficient peak load management and DGS.

A well-designed MRP can encourage all of these outcomes. The challenges, though, I mean, the big one is that, when you sit down and think about how to do this for GMP if you were to decide to do that, is coming up with that reasonable cost or revenue trajectory. That's the big negotiating challenge. You want to make sure that the customers get their fair share of the benefits, and, just in general, this involves some doing things differently than you have in the past. It's a new technology for regulating.

The good news for you is that to do this would not be that much different from what you already have with GMP. They already have an alternative regulation plan that only really differs mainly from a multiyear rate plan in their treatment of the capital costs. So now you just have to get an attrition relief mechanism that applies to all of its costs and not just to the O&M expenses like you have now. But it's still a new ball game, and so people need to learn that they can make important contributions with a new regulatory system that are analogous but just as important as what they may have done in the past with frequent rate cases.

MR. KNAUER: Thanks. Riley, go ahead.

MR. ALLEN: Mark, thanks for the presentation. In your view, just getting back to what you were just talking about, what are the most effective mechanisms for encouraging the utilities to control capital spending in the context of a multiyear rate plan?

MR. LOWRY: Well, the best thing is that the, I mean, that the budget be set in advance such that, if they, you know, they can't go over. If they go over, they're not going to get any extra money, and, if they underspend, then they get to keep some of that until the next rate case. So, I mean, that's the, you know, that's what Central Maine Power essentially had was an -- they had a CPI, well, it was a GDPI minus X escalation of their rates for like 15 years, and so under that they had a lot of incentive to cut their Capex.

Did I mention the one problem with that plan? There is an asterisk attached to it that, at the end of it, they came in to the regulator and said, Hey, our system now is so old that we can't continue with it unless we get extra money for our capital spending, and the Commission was unwilling to do that, and so they suspended operation under the, the MRPs.

That said, they haven't actually been in for a rate case since they claimed they needed 3 percent escalation every year. So I'm not sure what they were thinking at the time. But I think, even though that happened, the moral of the story is still that Capex can definitely be and utilities can be incentivized to contain their Capex if they have, you know, some sort of attritional relief mechanism that's insensitive to the Capex which is very different from what GMP has now, for example. It's basically like an annual rate case, an expedited annual rate case for capital.

On the O&M side, you've got the index, and that's been paying off like a slot machine. They've been doing really great in terms of containing their O&M expenses under that arrangement.

MR. ALLEN: What about the Totex approach, the RIIO approach, just lumping them all into --

MR. LOWRY: Well, you know, that's something you could consider. You know, no utility in North America has ever done that. The British approach has been proposed a few times, a couple of times in Canada. Never really -- regulators up there didn't ever really particularly cotton to it. You know, the British approach involves a, is based on the forecasts, okay?

Remember I talked about the four approaches to

ARM? One of them is forecast. So there they had these forecasts, and what happened is that the utilities, again and again they would forecast capital costs that ended up being a lot higher than their actual cost, and so that, in turn, compelled the Commission to develop this really -- first of all, to hire a bunch of consultants and to help them with engineering and benchmarking analysis, and then, too, they calculated this really complicated thing called an information quality incentive to incentivize the utility to actually be, give an honest forecast of its capital cost. So that's kind of what happened there.

I mean, but, apparently, it does work, but it, it took -- necessity is the mother of invention, apparently, but that all starts with their religious devotion to completely basing the revenue requirement on the forecast. I mean, they couldn't even index their O&M expenses. Meanwhile, say, in California, you know, that's been indexed since the 1980's, and they don't even use true forecasts for their capital costs there either. So that was kind of a peculiar approach.

MR. KNAUER: Rick had a question.

MR. WESTON: Thanks, Mark. That was terrific. I generally agree with your vision for the utility of the future, but I would tweak it in a couple

ways. One is, I think, in the longer term, peak load management is not going to be the issue, but, in fact, integration of variable energy resources, in which case you have a different, you have a different problem, and that is flexibility, and that ends up turning us to the customers through innovative rate designs and, in fact, payments for demand management in ways that we're not even beginning to fully imagine.

MR. LOWRY: Well, why isn't that peak load management, though? I mean, that's what I mean by peak load management, and that's why I say it's so important is that, the more you rely on these intermittent renewables, you really want to start encouraging the customers to go up and down and particularly to incentivize them to own storage, because that's a very effective tool for it.

MR. WESTON: I see your point. It's a vocabulary thing for me. For me, it would be just a dealing with the quick changes in load, the ramping and other needs, and it may not be a system peak, but it certainly will be a peak of the sort that you're referring to.

MR. KNAUER: Joanna?

MS. WHITE: Yeah, so I just had a quick question. You briefly mentioned a connection between a

multiyear rate plan and an integrated resource plan or a distribution utility resource plan, and traditionally in Vermont we've had IRPs that set out a plan of action, but the utilities aren't in any way bound to that plan; it's more about the processes that they've developed. So could you just talk about the ways in which an IRP has to be more robust or what an IRP needs to be in order to at least form Capex budgets?

MR. LOWRY: Well, what I meant when I said that was just that the process be, if there is such a process, that it be extended to the wires business as well as just the resources. And so, and that as for, Should it be tougher? Should the utilities be obliged to stick with the plan? I don't know that that's really appropriate, and, in fact, even with capital cost trackers around North America, usually, it's understood that the utility is going to end up doing something that's different from what they said originally.

I mean, you want them to have the ability -- first of all, you want to incentivize them to maybe find economies that they didn't realize, but also just conditions change since you got permission for a certain budget, and so it's very common, even with the, very common to give the utilities some flexibility with

these plans.

MS. WHITE: Yeah, sure.

MR. KNAUER: Eileen.

MS. SIMOLLARDES: So you've got ensuring customer benefits up there as a challenge and also something that Vermont regulation shared, and I'm curious as to whether or not you're focusing really on financial benefits, or are there other benefits to customers that you see from these plans, and, if so, what would those be?

MR. LOWRY: Well, when I say that, I'm mostly talking about the benefit, the financial benefits.

MS. SIMOLLARDES: Okay.

MR. LOWRY: Customers can also benefit from the marketing flexibility, another example, and, of course, if all of this helps to incentivize more embracing of demand-side management and distributed generation and storage, you know, you can say there's a benefit there as well.

And, really, I mean, just take that example of peak load management. I mean, if the, if just the general premise that the utilities are going to work harder towards a goal if they're incentivized, well, you know, having either or both a multiyear rate plan that includes capital costs and then also a PIM that

for peak load management and/or distributed generation and storage, I mean, they're going to likely take a lot more interest in it. Yes, ma'am.

MS. RICHARDS: This is going to be a difficult question for me to ask because I don't know how to ask it. Bear with me for a bit. So Washington Electric Co-op is a not-for-profit utility, and all the utilities in this room maybe except for Vermont Gas have some statutory requirements that we have to meet called strategic electrification. So what that means is we're being asked to get people to stop driving fossil fuel cars and convert to potentially electric cars.

So we're looking at our rate design right now, and I'm very interested in this whole proceeding because it's asked some of the same fundamental questions that we're asking internally as a small vertically integrated distribution utility at how we deliver our rate design.

So it's -- again, I'm having a hard time asking this as a question, but we've got an umbrella of rate regulation regulating rates. The utility has to charge for services, charge for, to its members, its customers. At the same time, we have laws that we're having to respond to that encourage net metering,

encourage the strategic electrification. I don't know which comes first, chicken and egg situation, and how does rate design fit in this overarching rate regulation? Is the question, I guess.

MR. LOWRY: Well, for one thing, as I've said, I think that people should be liberated from frequent rate cases in order to spend more time with this very valid issue. I think that, I mean, personally, I'm more of an aficionado of time-sensitive rates, time-of-use types of rates for the small-volume customers. I think that lots of times utilities would have more incentive to embrace those if they were, had more ability to contain their load-related Capex, the benefits of it by dint of stronger incentives.

But, you know, also, sometimes what they'll do in terms of addressing rate design, a couple of things, ways they could do it. One is you could have, you get started on the multiyear rate plan, and then that's always something that can be -- it's understood in advance that there's a window to reconsider rate designs and achieve revenue-neutral rate designs during the plan.

Don't forget, too, the part about revenue decoupling. I was saying that revenue decoupling is a good compliment for a multiyear rate plan, and it can

renew, remove the stress for, for a utility to use its rate design to help it recover its fixed costs by, say, raising your fixed charges a lot, which is happening all over the country today.

MS. ANCEL: Just to put a little more color on Patty's question, in Vermont we have a traditional rule that, to do any type of rate design, you have to do a fully allocated class cost-of-service setting on top of a freshly determined revenue requirements if we have a traditional case, and I wonder if your question, Patty, is, Have you seen, Mark, opportunities under multiyear plans where, like, that marketing flexibility provision you talked about might provide an avenue for utilities to do smaller scale rate designs around innovation especially targeted to state energy policy?

MS. RICHARDS: You know, I'm looking at it from the context of we have a very high energy rate. We have a two-tiered energy rate structure. We have a low fixed cost which is called $13 a month. First 200 kilowatt hours is 10 cents a kilowatt hour, which is very inexpensive for Vermont. Then anything over 200 kilowatt hours is 23 cents. We're sending a price signal to conserve. It's a policy level driven rate design. Now we're in a paradigm of trying to encourage higher use through EV plug-ins, through cold climate

heat pumps, strategic electrification. We're not going to do that at 23 cents a kilowatt hour.

So I'm trying to figure out what's the best way to reach these state goals given that the laws are requiring us to do that in this discussion with how we're regulating rates. I don't see how we can separate the rate design from the laws that we have in front of us and with this overarching how we're going to regulate those rates.

It's a fundamental question for me at how we're going to -- at the end of the day, we're going to collect -- I'm just going to call it $20 million. We need to collect $20 million in some, way, shape, or form, whether I load up my fixed costs and have a really high energy rate or I've switched that to, say, you know, a higher fixed cost and a lower energy rate so I have people incentivized to plug in EV's and how we regulate that from the PUC basis in rate making, to me, it all meshes together.

MR. LOWRY: Well, there certainly is some degree to which it meshes together, and so, again, the, for one thing, as I was saying before, usually, the rate design is permitted to take a separate course from rate cases. Apparently, from Charlotte saying usually the rate designs are only considered in rate cases

here, but, in reality, lots of times -- in fact, in California, for example, they have a rate case, and they have what they call post-test year mechanism is determined in one case, and then there's another phase in which rate designs are reconsidered after that. So there's always that opportunity.

But then, too, remember what I was saying about the various forms of marketing flexibility that oftentimes do accompany multiyear rate plans. One is optional tariffs. You can have optional tariffs for these energy transformation services. You can have more flexibility in terms of offering those between, between rate cases, some of which flexibility GMP has right now.

And then the other thing is that, if there is an agreement that the company should be moving in a certain direction of rate design, then it could be agreed to in advance that over, say, the four years of the plan that, say, the default rate designs gradually move in the direction, for example, of time-of-use rates where you mentioned the EV's where you could have a much, much lower nighttime usage charge, and you could evolve towards that even on your default rate over the term of four years, or, like I said, it could be a, a optional tariff that's offered to the customer.

MS. WHITE: Yeah, one more question. We have a utility that does performance incentives, and I just wondered if you, in our experience -- and, Dave Westman, you can correct me if I'm wrong on this -- it's just as much like time and blood, sweat, and tears to set what the PIMs are, what level, what different kinds of compensation, you know, did they achieve them or didn't they achieve them, and verification, and I think we have almost as much litigation over that as we do in a traditional rate case, and I wondered if --

MR. LOWRY: Now you've got my curiosity up when you say you work with a utility. What's the utility?

MS. WHITE: So I'm talking about Efficiency Vermont is a utility that has effectively a multiyear plan with performance incentives, so we do this already, and I'm skeptical of the claim that there will be lots of time and money saved on regulatory proceedings, and I wonder if you or anyone else had put any numbers on that, like, looked at FERC Form 1 spending on regulatory proceedings for utilities that had multiyear rate plans versus those that didn't. And so that's just a skepticism, or I'm just probing that a bit, and I'm wondering if you had more evidence on it.

MR. LOWRY: Well, I would think, first of

all, one comment about that and, yes, there are certain champions of adding a lot of PIMs to the regulatory process, and they can be very complicated, and, like I said, there's a cottage industry developing around these PIMs, giving consulting advice about PIMs and how to do the tests, and so, yes, that, that can get to be a problem.

A lot of that, by the way, though, doesn't really have that much to do with the multiyear rate plan. I mean, the multiyear rate plan is trying to replace the general rate case. Now, whether or not you add a DSM PIM to that, if you don't like the idea of a DSM PIM, like, say, a peak load management PIM for GMP that sounds like a nightmare, well, you don't have to have that.

There's certainly savings in the reduced frequency of general rate cases. That's the most certain thing about a multiyear rate plan. So I think what you have -- I'm sorry.

MS. MCHUGH: Are there any studies that document that?

MR. LOWRY: Well, I think it's sort of self-evident that, if you go from having a rate case every two years to a rate case every four years -- what did one person say at the last conference, that they

had a whole bookshelf of just the evidence, not including the information requests, from the last CVPS rate case on their bookshelf. Did anybody in the room say that, had said that in the last meeting you had? I read the transcript of it.

So that was just the evidence of the parties without getting into the, the, you know, getting into the data requests and all that. So, to me, I have to say that I think it's sort of self-evident that --

MS. MCHUGH: But, quantitatively, are you aware of any?

MR. LOWRY: Well, I know this too. People haggle a lot about the design of the multiyear rate plan in a rate case that leads to one, but it's nowhere near the same as a rate case. I mean, in fact, typically, if it's added to a rate case, it might account for maybe 15 percent of the cost of the rate case would be haggling about the multiyear rate plan. I mean, you're only doing that every four or five years.

CHAIRMAN ROISMAN: Right, but the question she's asking you is, What is the cost of that rate case?

MR. LOWRY: Yeah. Well, who has estimated the cost of rate cases per se? I've seen estimates.

Nothing comes immediately to mind, but I've seen estimates, and, of course, it depends on the jurisdiction and the size of the utility. I mean, in California they were enormous utilities.

It's kind of interesting that in Ontario they went to multiyear rate plans partly because there were so many utilities, but in California just the utilities were so darn big, and back in the 1980's they were having all these problems with nuclear power plants and buying too much purchased power from unregulated generators, and so the Commission ordered them to only come in for rate cases every three years with the so-called California rate plan which is in effect to this day.

But, in that case, it was because they were so big, each individual utility. Obviously, Green Mountain Power isn't that big, and there also aren't 20 or 30 utilities in the state to regulate. So that's a blessing. That's one argument for cost-of-service regulation there is that the regulatory burden isn't quite as big.

MS. ANCEL: Just as a chaser. On behalf of Green Mountain Power, we'd be happy to provide the Commission with an accounting of all of our rate case expenses including Department of Public Service

blowback expenses, all of which flow to customers. So, if it's helpful to the stakeholders, we can provide that. It might make sense to get closer to the, you know, at the end of briefing of our rate case, but we would do it then.

MS. MCHUGH: That would be helpful.

MS. ANCEL: I'm pleased to do that. And, also, just a follow-up to Joanna's question. Mark, I just want to make sure we understand. Are there multiyear rate plans that don't, that you've seen that don't have PIMs?

MR. LOWRY: Well, they're always going to have the PIMs for the service quality because, you know, what happened, not so much in the electric industry, but in the telephone industry they were the first to go down this road, and so sometimes in the very early days of telecommunications MRPs, they didn't have the service quality incentives, and I know in my own state of Wisconsin they actually terminated a lot of the people that were responsible for the quality. So, when the quality went kerflooey and the Commission went crazy, it was hard to get them back because they, they let them go.

But so after that they started realizing it's kind of a no-brainer to have these service quality

incentives, and ever since then that hasn't really been a problem with the general approach to regulation.

So, no, you don't have to have all of the other PIMs, and I was trying to be as level, balanced in my presentation as possible here. Because, actually, you go around the country today, and, when people talk a lot about PBR, a lot of them are talking about these PIMs that you're talking about, and, yes, they can be complicated.

It's a little bit like, the difference between a PIM approach to, say, incentivizing DSM and the MRPs, to me, is little bit like revenue decoupling versus an LRAM. With an LRAM you have to have the lost load estimates. With the decoupling you never have to get into that. Similarly with an MRP, you just incentivize them to use DSM. I still think that, if you want the deluxe result, you'd want add a PIMs, but --

MS. ANCEL: We might actually challenge that under the concept that, like, if a utility is supposed to deliver really superior outcomes for its customers, and, as I understand it, all that PIM is doing is adding on, it's adding further costs onto rates by further compensation to utilities to achieve certain outcomes. So, if the utility takes on the obligation to achieve those outcomes, you could, in concept, have

a multiyear plan without a PIM; is that true?

MR. LOWRY: Oh, yeah, absolutely, of course. And a good example, just to help you with your point that the Brooklyn-Queens Demand Management Project, if you follow the trade press, there have been people who have complained about that. It's not actually exactly a PIM in that particular case. But they complained that the benefits of the Brooklyn-Queens Demand Management Project are not what they, what, are not commensurate with the compensation because it ended up it wasn't, you know, that those so-called billion dollars in investment that they were going to postpone wasn't really needed anyway. So there's been critics of that particular use of a nonwire alternative.

Nonetheless, they keep growing, and New York and California have both adopted these, and I think they're thinking of them in Massachusetts as well.

MR. KNAUER: Riley, you had some questions?

MR. ALLEN: Yeah. For both yours and Rick's presentation, I take it that the multiyear rate plan, in point, isn't necessary for at least some elements of what we're trying to achieve. That is, you could have PIMs in relation to incentives to do, serve customer ends in the context of a normal traditional regulation plan. You could have decoupling in the form of a

traditional regulation plan. The multiyear rate plan component is distinct, and I'm trying to understand first whether it's your view that that's desirable, a desirable component of the plan going forward. I think it's yes, but --

MR. LOWRY: Yes. No. I'm, I'm the person in this whole PBR thing that said, Hey, wait a minute. PBR is mainly about multiyear rate plans, and this PIM idea is, is kind of, is the newcomer, but, and, in fact, as I've said during the presentation, that even the, the commissions that are most likely to experiment with these fancy PIMs, they already had multiyear rate plans. They didn't abandon them. It wasn't one versus the other.

So I, in fact, remember, I was talking about how I wrote two papers for Lawrence Berkeley Labs? That's why, because Berkeley Labs thought there was a need for a second paper to just hone in on this topic of multiyear rate plans because so much of the talk, the PBR talk, has recently been about the PIM part of it.

But, you know, I wanted to answer your question. I mean, yeah, you could have just traditional regulation, add some PIMs, and you could have revenue decoupling. In practice, though, I think you'll find that, you know, the states that have been bigger on the

PIMs, like I say, they also believe in multiyear rate plans, and that's, that's where you're getting your regulatory cost savings. Maybe that creates the luxury of having a fancy PIM for peak load management.

MR. ALLEN: What's the evidence say are essentially the benefits of the multiyear rate plan component? I mean, is there evidence that suggests that -- I mean, you had the 10 percent cost reduction, I think, associated with that. I assume that's based in some analysis you've done.

MR. LOWRY: That's right. Well, that was, see, in my -- that's again why Berkeley Labs wanted to have a paper that was just about this. And so one of the things that we did, first of all, just generally raising the profile of the multiyear rate plan issue, which actually is -- I've already shown you -- is quite popular around the country, but still there's a lot of confusion as to what PBR is really all about.

So the paper was, first of all, to look at case studies, but also to look for any evidence of what the impact is of multiyear rate plans. So I, I addressed it in two ways. First of all -- and no one's ever done this before, so, you know, got to get started somewhere. What I did isn't going to be the last definitive word on this.

I mentioned and I presented the evidence about the incentive power model. That's where that 10 percent thing came from. But also what I did is I, I measured the productivity trend of, like, 90 electric utilities since 1980 as providers of distribution services, and I did that partly because then everybody provides those, where some of them got out of the, about half of them got out of the generation.

So you can always look way back to 1980 at power distribution productivity, and so what I did in the report is to see whether there was any difference between power distribution productivity in utilities that either were under MRPs or just stayed out of a rate case for 10 or 15 years. You remember I was talking about how some utilities have just stayed out of rate cases. And so we looked at that group of utilities, a group that includes a lot of very well-respected utilities, I might add, like Duke Energy and Florida Power & Light were outside of rate cases for 15 or more years.

So, yes, what we found is that there is a statistically significant impact of staying out of rate cases on cost performance. There's a positive impact.

MR. ALLEN: The final component of my question is, Is there a sweet spot in your mind that

reflects kind of the balance of too hot and too cold, if you will?

MR. LOWRY: Well, I think right now where they have the -- I mean, you can always do a -- you can always get started with more of a transitional step where you maybe just have a three-year case plan the first time around until you see, you know, kind of get your feet wet on it. I think the sweet spot is what you see as the most common types of multiyear rate plans. It would stand to reason that that's the sweet spot, and it tends to be more like four- and five-year plans.

Whereas, as you also heard, the British have gotten ambitious, and they said, We're going to go to eight years between rate cases, not just for a particular utility that feels like trying that, but for all utilities in Britain, and it's like 14 companies.

MR. KNAUER: All right. Folks, we have a hard stop at 4:15, so that's ten more minutes, so, Brian, you're going to be the last question, okay?

MR. WINN: So isn't there just a benefit of having the discussion about a multiple-year timeframe versus in traditional regulation, whenever the utility decides it wants a rate increase, it comes in and it gives you maybe this year's capital expense and the

rate year's capital expense, whereas in a multiyear plan you're going to get a four- or five-year look at the capital expenditure when you're developing that plan during that rate case?

MR. LOWRY: Some will say that. I mean, that, that, sometimes that's said to be a selling point is that it compels the utility to take a more forward-looking view of the utility, makes them look at the business plan.

Now, but it's not entirely true because you don't necessarily -- for one thing, some regulators don't want to do that. That's what happened in Maine, that Central Maine Power went off of its plan, and then they wanted a plan that called upon them to sign off on their Capex for the next four years, and they said, We're not doing that. In fact, they were so adamant about it that they interrupted the proceeding after about two months to just say clearly, We will not do that, and so then the company had to resubmit.

So not everyone agrees on that benefit, but I think, I feel, in an age when there are these potential substitutions of distributed generation and storage for distribution, that maybe, you know, it's become more incumbent upon regulators, and when utilities -- not GMP, by the way -- but other utilities are coming in

asking for these big capital spending splurges, that it is more incumbent upon the utilities to be thinking about their distribution business plans, anyways.

MR. KNAUER: All right. Thank you very much for your presentation and your answers. So, as the Chairman announced at the beginning, we will be communicating with the group about rescheduling the next workshop. As previously advertised, we will, that will be an opportunity to argue the merits of what we've learned today. To the extent that people have other topics that they think the Commission should be addressing at that workshop or at a future workshop, please do not hesitate to communicate with them and us. And I guess that's it, unless the Commission has anything else to say.

CHAIRMAN ROISMAN: No.

MR. KNAUER: Okay. Thank you, everyone.

(Whereupon at 4:07 p.m. the hearing was adjourned.)

C E R T I F I C A T E

I, Sunnie Donath, RPR, do hereby certify that I recorded by stenographic means the Workshop re: Vermont Public Utility Commission request for second workshop on utility rate regulation at the Vermont State House, Room 11, 115 State Street, Montpelier, Vermont, on September 12, 2017, beginning at 1:30 p.m.

I further certify that the foregoing testimony was taken by me stenographically and thereafter reduced to typewriting and the foregoing 108 pages are a transcript of the stenographic notes taken by me of the evidence and the proceedings to the best of my ability.

I further certify that I am not related to any of the parties thereto or their counsel, and I am in no way interested in the outcome of said cause.

Dated at Westminster, Vermont, this 19th day of September, 2017.

_____

//Sunnie Donath, RPR