HARVARD ELECTRICITY POLICY GROUP

VIRTUAL SESSION
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Rapporteur's Summary*

Dispatching Demand: A Critical Element of Future Energy Systems

Technological progress and public policy pressures are accelerating decarbonization of electricity supply. Increasingly, states and utilities are announcing 100% renewable, 100% clean or net zero carbon targets and mandates. With intermittent sources as the dominant source of supply, there is concern about the loss of system flexibility. Hence, activating flexible demand could well be key to managing future electricity systems cost-effectively. Flexible demand tends to occur at the distribution level. This in turn creates at least two issues: First, how can load flexibility be activated to help manage the electricity system? What interactions need to exist between wholesale and retail price signals? What role do aggregators play, what is the role of retail pricing – and who should determine retail pricing – competitive suppliers or wires companies? Second, is a wholesale (or perhaps transmission level) view sufficient to determine optimal participation of demand flexibility? Put differently, might constraints and costs at the retail level be important enough to necessitate their consideration when creating incentive structures for demand-side flexibility in future electricity markets?

Moderator.
Thank you all for joining. So, this is a first for me. It's a good one to moderate, a little coming full circle for me since my Ph.D research several years ago now was exploring the role of the demand side and making electricity markets more competitive.

This theme emerged from discussions we had internally around the hypothesis that as more and more variable renewable energy sources come into the supply of electricity, the role of flexibility would likely increase. And since demand is potentially a big source of flexibility, the theme emerged: how can we figure out how to engage that potentially flexible demand more actively and make it a tool in making markets balance?

In that spirit, we have four speakers. Our first speaker will ask all of the relevant questions and then our second will provide all the theoretical answers. After that., our third speaker will address what's practically feasible. And then our final speaker will give a preview of things to come, as, as I just mentioned, as the market might see more and more of these renewables coming into the market. So that's the idea. I think the each of the speakers will give a 12- to 15-minute presentation and, as we pointed out, no questions. But then we'll take a break.

In the break, we're going to have a 15-minute or so break where we sort of put all of you randomly into various breakout groups. We tried that last week. That worked fairly well. It gives you an opportunity to catch up and maybe even discuss some of the stuff that you heard in the four presentations.

With that being said, I'll just hand it over first to Speaker 1 to get us started.

Speaker 1.

* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the discussants. Participant comments have been edited for clarity and readability.

I am coming to you from Orinda, California, where we have no power right now. Running on a small generator, which I thought would save me. But it turns out that Comcast doesn't know how to use generators. So we have no high-speed internet. So this is on my phone. And we've tried it. I think it's going to work; I'll do the best I can.

For my talk, I put the title "Dispatching Demand: A Critical Element of Future Electricity Systems?"—because, as I thought about this, I actually wasn't sure that was the real role of demand in the market. I should say before I start this talk that although I'm a member of the Board of Governors, nothing I say here reflects the official views of CAISO or, obviously, UC Berkeley.

I've obviously been thinking about demand flexibility for a long time, and more so now, as we've seen growing increased intermittent generation. And I don't think there's any question that the demand side has to play a critical role. The question is how to do that.

Voluntary reductions have historically been the way we've done this. And California, in fact, just in August and September, was calling for people to reduce their consumption, with no real incentives in place. I and many others in this meeting have for years been talking about dynamic pricing. As an economist, that is of course what occurs to me first. But there's also this view that demand should be dispatchable, that we should use demand as a dispatchable resource.

I'm going to come around and talk about the possibility of actually combining those in a sense, by using forward quantity contracts with rewards for deviation. And then there's this somewhat separate question, but I think really important, of how we actually go about integrating demand. Do we do it in the retail market, in the wholesale market, or in both? That's another important aspect here.

I started out because people often talk about demand as a resource, which makes me pretty uncomfortable, and they think of it as just negative supply. That's always made me a bit uncomfortable because demand in electricity markets is very different than in most, in that the buyers generally have what are called requirements contracts, the right to buy all they want at a predetermined price. That price nearly always differs from the actual marginal cost of supplying the power.

In California, on average, it's actually more than double the marginal supply costs for residential customers, work Jim Bushnell and I put out last year. And in nearly all markets at the super-peak times, the prices customers face are well below marginal cost. As a result, when we started talking about reducing demand, we have to think about, what are we reducing demand from and what are the economic incentives that we're putting in place when we start setting up baselines? There are, of course, both moral hazard problems that people actually, and there's a lot of evidence, have gamed their baselines, in order to get paid more for reduction.

Secondly—and I think the bigger problem—is the problem of adverse selection in participation in these programs. In fact, there's a recent master's thesis out of UC Davis, where a student looked at UC Davis participating in the Cal ISO demand response program and showed that without changing behavior at all, just by careful selection of when they participate, they could make a lot of money, which is obviously not what we're trying to accomplish.

This sort of requirements contract is a very unusual arrangement in markets. In fact, it's very hard to come up with anything that looks like it in any other market, with the exception of forward contracts which are not requirements contracts in the standard sense but do bear some relation.

As an economist, one of the first questions that occurs to me is why isn't dynamic pricing just the answer. Why don't we just have dynamic pricing and be done with it, and customers face the real cost of their consumption up or down? One of the answers that I've run into, and heard from many people, is that doesn't really solve the problem because electricity is really different. You need to balance supply and demand every minute.

So you want demand responding in a way that is dispatchable. Of course, you hear this from grid operators: if we're going to really treat it as a resource, it has to be a resource. We have to be able to call on it to make to supply power by reducing their consumption. The argument has been made that demand should be dispatchable. That's a really critical component to helping to balance the system in an electricity market.

That's a function, the fact that electricity really is not like other products and that supply and demand have to balance minute by minute. But I wonder about that because when we organize demand participation as payments for reduction from a baseline, in a sense I wonder how much we're actually exacerbating the problem we're trying to solve.

The problem, of course, is these peak times. Until the customers actually get called, get dispatched, they have no incentive to reduce their consumption—recall that they're generally being charged something well below system marginal cost at those times. And I wonder if we instead did have full dynamic pricing, how much less dispatchability we would actually need? Because we would be flattening those load profiles.

Yes, you wouldn't be able to call on demand to reduce their consumption, but we'd have less need to because we'd have a smoother load curve to begin with. Obviously, when you do get into the moment you need to reduce demand or you need to balance supply and demand, the demand’s sudden adjustment wouldn't be available, if we did that. But price would be sending the signal that we're in a very tight market and we'd probably have a smoother load profile to begin with.

So that's my concern about making demand dispatchable. But if we're going to have a demand response type of program, I think there's also this question of who should implement it. Is this more appropriately a retail market function or wholesale market function? I want to step back from FERC Order 745 and not get into the legal or jurisdictional issues there. I want to ask the question, what is the way from an operational and economic approach that we should do this?

One argument is that this is dispatchable demand and we know who does dispatching. That's the grid operator. So shouldn't it be run by the grid operator? And I think there's something to that. But I think there's also an alternative view, which is that any one demand dispatch or customer isn't really what matters. What matters is the aggregate, and if we're aggregating demand quantities, because that's what really matters to balancing the grid, couldn't we have load-serving entities do the aggregation?

The load-serving entities would just offer net demand or what the grid operator would see as demand to the grid operator. Then the load-serving entities could do anything they want to incentivize demand reduction at peak times. They could have dynamic pricing. They could have critical peak pricing. They could pay for demand reduction.

In some ways, I view this as letting 1,000 demand response flowers bloom. That is, doing it, letting all of the LSEs figure out how they want to reduce demand at those critical times, and then offering those services to the grid operator and being ready to supply them, possibly by direct load control, possibly by very high frequency dynamic pricing, and possibly by actually paying their customers for demand reduction. Of course, there are some good examples of all of those out there, including some third-party operators like OhmConnect, who are in the business now of offering demand reduction into the grid operator market.

But *they* take care of how they interact with the customers. These entities do it in ways that can be pretty creative, and are likely to be more creative and likely to explore more options than when it is centralized through the grid operator.

In some ways that's attractive, particularly to someone who's thinking about the grid operator side of this, because it takes the grid operator out of this demand response market and says, "Look, we are in the business of making a market for electricity and we are the middle company for that market. We don't get into demand reduction, demand increase. We just make a market in electricity." And I think that's what grid operators do. I think that's what they're good at and very impressive at, in most cases, and it would move the operation of these sorts of demand response downstream to the load-serving entities.

If we are going to have demand response programs, I wonder about how do they coexist with dynamic pricing. I'm not ready to give up on dynamic pricing. One argument is that dynamic pricing is the somewhat longer-term, perhaps day-ahead, market mechanism and demand response is the "emergency response" that is the real-time adjustment.

That's certainly when I talk to grid operators, how they tend to think about it—that the demand response is what you're actually doing in real time to make the system balance. Of course, if we're going to do that, then it seems that the real-time adjustments should not just be paying a price for going down, but also charging for going up.

I think it's pretty hard to see why those shouldn't be symmetric, because any one customer is a pretty small part of the market. And the somebody else who's not on one of these programs, increasing their consumption suddenly, is imposing a demand on the market that exactly offsets somebody else's reduction. Why wouldn't we price these symmetrically? If we do go down that road, in a sense what we're calling demand response is back to what we have called in commodity markets for years—forward contract. And then pricing deviations from that forward contract at the spot price.

So, in a sense, if we are going to create a demand response product that actually does treat deviation symmetrically, we're back to a forward contract. Of course, as an economist, that's something I'm much more familiar with and comfortable with. But I wonder if that does solve the problem, or if people who are bigger advocates of demand response would not see that as sufficient.

So those are my comments. They're all questions as you notice, not solutions. When we started setting up for this session, I said I wasn't going to really have any answers. I've just been thinking about this and I have a lot of questions. I'm very much looking forward to the other panelists answering all these questions or, if not them, some of the esteemed participants in the conference. Thanks a lot for including me.

Moderator: This was great. And the good news is that we have Speaker 2 next. As I said, he's going to have the answers.

Speaker 2.
All right. Yes, I am ready. Thank you. Let me begin by just making a disclaimer that I am personally on a time-of-use rate where the differentiation between peak and off-peak is significant. My peak price is almost 50¢ a kilowatt hour and my off-peak price is under 20¢ a kilowatt hour. It's the EV 2A rate as PG&E calls it, designed for people with electric cars. I have a Model 3. I also have solar and a battery. So I'm trying to live the prosumer experience in the presence of all of these new forces that are coming our way.

So when I speak here, I'll speak, partly as a customer, partly as an economist, and partly as a consultant. All of it is rolled into me.

I wasn't sure what dispatching demand meant, to be perfectly honest. I think Speaker 1 has shed a lot of light on what that means. I'm using a very broad sense of balancing demand and supply, using dynamic pricing to balance demand and supply. That's the focus of what I'll be talking about.

There are many ways to dispatch demand. There are flex alerts and other voluntary appeals, and we saw those in mid-August here in California. We saw those almost 19 years ago, again in California. They work up to a point. People tire out and at some point they stopped responding. But it's always there, a beg to please cut your usage.

Second is direct load control of certain appliances like air conditioners. California summer peaking. Other areas have a lot of water heaters, as well. All of those can be controlled and they have been controlled for 50+ years. It is not anything new.

Then you have curtailment and interruptible rates, which are essentially designed for emergency situations. You get a break on your rate if you agree to curtail or interrupt your load when called upon by either the utility or the grid operator. That's typically designed for large customers. Again, those have been around for a very long time.

If all of these fail, just turn off the power and that always works. So those are generally what I would call traditional and primitive methods.

The focus that I will have addressing Speaker 1's questions is, send price signals that vary dynamically in response to the severity of the scarcity. What I have is a time-of-use rate. It's not dynamic, but it certainly has resulted in me taking my load shape and making it follow the price curve. We have about, I believe, 500,000 customers out of five million on these rates in the service area in which I reside. But they are not dynamic. That dynamic element is very small. And that's where the challenges and the opportunities arise.

I'm going to deviate a little bit from the moderator's charter and actually get into some data here. I don't mean to take anything away from the next presentation coming up. I'll just talk about the broad empirical evidence that we have. Since the California energy crisis of 2001, people have been scared of having another crisis. They have done pilots and pilots and pilots, and all together we have been tracking those just as a hobby, you could say, at Brattle.

We have 371 experimental tests of time-varying rates drawn from nine countries. The kinds of rates that we have are shown here vary at a high level, so *n* is of course the number of tests. The countries are listed as the rows, CPP is critical peak pricing, TOU is traditional time-of-use rates. That's the one I am on. Peak time rebates is PTR, which requires the baseline and all the issues that come with it. And variable peak pricing, which Speaker 3 is going to talk about in some detail.

So, altogether, 371 tests have occurred over the last 20 years; 108 of those involved CPP and 69 involve PTR**.** Those are dynamic, they are not fully hourly pricing, but they are dynamic.

What have we learned from these tests? That's shown on the next slide. We have taken the data and done some very simple regression analysis, and we have plotted out these curves or arcs. The arcs show that the peak demand response to the peak-to-off-peak price ratio in a fairly predictable way. The bottom arc is simply price with no technology wrapped around it, and the lighter color is when you wrap technology—like a smart thermostat, a Nest or ecobee—around the price. You get, obviously, a lot more response. This is solid evidence. It's proven that it works, but we still have hesitation and reluctance, and I will address some of those issues in the next few minutes.

The question naturally arises, given all this incredible experimental evidence that, by the way, didn't exist until 20 years ago. What have we done? Have we done any deployments? Spain, which did almost no testing, decided to go ahead and just roll it out. So it's the default it's for all residential customers today in Spain. Customers with contractor demand below 10 kW pay an hourly market price. Those without smart meters are assigned a deemed profile and pay an average price.

How did I discover this about Spain? I actually reached out to France. As you know, France has been a leader in marginal cost pricing for years and years. EDF, the utility, their CEO at one time was a Ph.D economist. You saw a lot of excitement there. They had a time-of-use tariff called Tempo.

The Tempo tariff is no longer there. They restructured the market. Retail competition has arrived. And so when I reached out to some professors and friends, I said, "Tell me, what do you have about innovative retail rate design?" They said, you will have to go to the "west of the Pyrenees." They didn't say you'll have to go to Spain, they said west of the Pyrenees. That's how we discovered that Spain has all this excitement

So 50% of the customers are on real-time pricing, or 13 million customers. That's incredible. People have gotten used to saying there's nothing new happening in Spain. Well, here we have it. They have really set the record here in terms of real-time pricing.

Then we go to the Nordic countries 7% of Finnish residential customers pay an hourly price that is tied to the spot price in the regional market. 78% of Norwegian household contracts are tied to spot prices. Europe is incredibly ahead of us, which is something that I think is very revealing.

Now back to the US and, of course, I know Speaker 3 is coming up soon. So all I will say is that they have probably shown that, even in the US, this will work. I actually asked a man from EDF many years ago with whom I used to work at EPRI, I said, “So, a lot of those things that work in France, why don't they work in the US?” He had lived in both countries and also held a British passport. So Richard Schomburg, he said to me, “Europe is focused on conservation and the US is focused on production.” He said, “There is a huge cultural divide between the two continents.”

Well, I'm happy to say that OG+E has shown that even in the heart of the US, just north of Texas, we have seen in what some people call “the oil patch,” but really they have shown the way and they have left California behind. So hats off to OG+E, and we'll get more details very soon.

Then you have Georgia Power. I believe Georgia Power has the kind of rate the Speaker 1 was talking about. It’s a two-part rate, there's a forward contract kind of a construct and then, at the margin, you pay the real-time price, both for a load increase as well as for a load decrease. They have about 2,200 commercial and industrial customers in real-time pricing. They have had this going back to the 1990s.

They had a pricing manager come over from Eskom in South Africa, where that concept had originated. It was being applied to the large mining customers. He brought it over to Georgia. and Georgia has shown that it can work. Oklahoma has shown it can work, as well.

So how about California? Some people call it the digital capital of the world, and rightly so, Google and Facebook and Apple and all of those companies that we are using day in and day out, like LinkedIn, etc. They're all located in California, particularly in the Bay Area. So you would think they would have incredibly smart consumers and incredibly smart rates. Well, it does turn out that they have incredibly smart consumers in California. Roughly half of the US population of photovoltaics and electric vehicles resides in California. And half of that half is in the Bay Area.

You have all of these technologies. By the way, these are from my house. And I'm not trying to showcase my house. I'm just saying that I was late to the party. Many people are way ahead of me. So change is coming. The rate I'm showing you in that little clip on the upper right, the rate where the summer price for peak energy is close to 50¢ and the off-peak is close to 20¢. But there is no dynamic element, it's still pretty static. You could say it's shaping the load. But it's not dynamically shaping it.

It turns out that California has been doing pilots with dynamic pricing, even before the energy crisis occurred, going back to the 1990s. Then in the late 2000s, the California Energy Commission, where Art Rosenfeld was a commissioner at the time and Jackie Pfannenstiel was the chair. They held a stakeholder session. I was part of it. The two commissions were involved. A decision was made to deploy critical peak pricing as the default tariff for C&I customers.

But many customers opted out of it. Because when they would call customer support, the utility person would say, “It's a complicated rate, just get off it and don't call me again.” We did surveys and that's what we found, that the buy-in was not there. What about residential customers? Well, it's opt-in. Actually, I tried it out for a few years. It was interesting. Then I discovered they were calling the events even on the days when the weather was mild and there was no demand supply discrepancy

So I called the pricing manager, who I knew somewhat well, and I said, “How come I've been called on days when there's no obvious shortage?" He said, "We have to get our revenue. We have to call it 15 times." So you have some unusually interesting incentives that have gone awry, both for the utilities and the customer.

Finally, because of all of the challenges the state has faced with the energy issues, they are now moving to default time-of-use rates for all residential customers. But these rates have been around for 40 years. There's nothing innovative about them. I've been on them since 1990. They don't have a dynamic element. As Speaker 1 indicated, the grid is becoming more and more renewable, more and more intermittent and variable. We will need demand flexibility in real time. We can't get it through time-of-use rates. So why are we doing time-of-use rates 40 years too late?

I'll let the other speakers address that question. I have my theories, but they're best saved for a post-retirement coffee party. OK, so California needs to move to default CPP, I believe most of us would agree, as the grid becomes more renewable. I have a little editorial on that on *Utility Dive*, which, when I published, it was greeted with positive and negative sentiments, with one person saying, "You've been doing this for 40 years, you just don't know how the electricity business works, do you?"

Are we going to see this in our lifetime? "You can always expect a radical new idea to generate three reactions." This is from Arthur C. Clarke. The first one is, "it's completely impossible." In other words, you're a fool. Second, "it's possible but not worth doing." Don't waste your time. And when it happens, "I said it was a good idea all along." So, I remain cautiously optimistic, and that's my presentation.

Moderator: Thanks so much. Now we're going to get the practical perspective from Speaker 3. He'll tell us about the dynamic element to this, in practice.

Speaker 3.
Okay, thank you. Thank you for inviting me. I appreciate the opportunity to share what little we've learned at OG+E. Just in case you didn't know, we serve in Oklahoma and Arkansas. We have about 90% of our retail customers in Oklahoma. The remainder are in Arkansas. This is our resource mix. We do have about 800 megawatts of wind.

What I wanted to talk about was how we think about pricing at OG+E. I'm not saying it's right, it's to just what works for us. At the start, before our current era, we had a fuel mix—about 75% of our kilowatt hours are coming from coal and 25% were from gas.

We had traditional rates. We had inverted block, declining block rates for residential. We had demand charges for our commercial-industrial customers. We offered a two-part RTP program, beginning in '96. I dug it up, and our residential rate started in about '82 or 1983. I will tell you that only about 30 people participated, and I believe they were all in the rate department.

We got our first wind resource in 2003. It was 50-megawatt PPA. We offered our customers an opportunity to participate. They could subscribe to the program and they would receive a credit. Their fuel cost adjustment would be replaced with the price of wind. Then we also introduced a fixed-bill program, modeled after that of Gulf Power and Georgia Power. That was what we had then.

OG+E had requested permission to build another coal plant and the commission said no. OG+E decided to go a completely different direction. We said, “OK, we won't do any more fossil fuel. We will look at adding wind to meet our energy requirements, transmission to get the wind to the load center, and then use price response or demand response programs to meet our peak.” That was our strategy, set back around 2008, that we used to get us to here today.

We built out the transmission system. We added 800 megawatts of wind. We offered our customers, again, a chance to participate in the wind. We would sell them RECs. Then also, we won one of the DOE grants and we got to build out AMI for our system completely and have our smart grid build out. We had proposed rates, our variable peak pricing with a thermostat and without a thermostat. The same thing, we tested critical peak pricing. We looked at time of use. We even offered a discount to senior citizens that if they would participate in time of use, it would let them try it. We gave all these customers our best bill guarantee. In other words, at the end of the year if you would have paid a lower bill under the standard rate, we would give you the difference

We would look at our C&I crowd and we already had a load reduction program that we liked. We also looked at RTP. At its peak in the late ’90s, early 2000s, we were up around 30-35 customers in RTP. Then it really dropped off in the 2008-2009 timeframe, when the gas prices spiked.

So we reintroduced a program we call Flex Price. We kept RTP. Flex Price was just a simplified version of RTP. Instead of hour pricing, it used four-hour blocks. Then we also looked at peak-time rebates. A lot of people were getting good results and we did a pilot with that.

We had another change. The SPP market opened. We saw an increase in people looking to net meter, install solar on their roof. Our industrial customers became much more interested in load reduction. We were able to subscribe many customers to that. We offered our utility solar program to customers. We also had by that time come to appreciate that VPP was working quite well for us. CPP was really lagging behind and so was peak-time rebates. So we stopped those two programs.

And so we're sitting here today. Now our customers receive about 35% of their kilowatt hours from coal. You can see the mix, there: 27% from wind, which really didn't exist in 2000 for Oklahoma, and then gas and we've got some other resources. That's how our pricing has changed over time as our supply and delivery and in-market environment has changed. And that's what I think is important, is to stay flexible.

In my environment—I work in a vertically integrated regulated market—there are really three parties. There's the regulators. There's customers. And then there's OG+E. I have to offer programs that I can entice customers to subscribe and that I can get regulators to approve. That is the viable market space in which I work for optional rates.

We did our market research. We've done this a few times, we do discrete choice conjoint. We put price plans out for customers, and we measure which one they prefer. We've looked at what we classify as price security programs, whether it's a flat rate or a guaranteed flat bill, a fixed-bill program. We've looked at what we call block plans, similar to what Speaker 1 was discussing, but we describe it like cell phone plans where you buy a block of kilowatt hours. If you exceed your block you pay an incremental price. We also look at RTP, VPP, TOU, and we leave the standard rate there.

What we found is there's about a third of our customers who are interested in price response rates. There's a larger segment that's interested in price certainty. They want to know what their bill is each month. And there's some others that want to stay on the standard rate. But the key finding is, if you're only offering your traditional or standard rate, most customers don't want that.

I had one colleague explaining to me that, and he was quite correct, that customers know two things about their electricity: the bill comes once a month, and it's too high. That's basically how our customers saw electricity until we started advertising. We started talking about our price plans. This is the week of the peak this year for VPP. Peak was on Monday.

This is the peak day. You can see the orange line is VPP with a thermostat. The blue line is VPP without our company-supplied programmable communicating thermostat. And the dash line is the standard residential rate. As you can see, the system peak does not occur when the residential peak occurs. With VPP programs, we do get some rebound, we get some pre-cooling, which is to be expected.

What we found is that customers are interested in participating, but not all customers. But it's OK. We don't need all of them to subscribe. What I'm more interested in is figuring out which pool does that customer—do they want to be somebody who wants a price certainty program, or do they want a price response program? Because it's very expensive to market to customers, and I want to figure out where you want to be. And then I know how to approach you in the market.

We prefer to offer our customer choices. We prefer to offer a portfolio of prices to customers. We offer them the standard rate, we offer them fixed bill, and we offer them a couple of flavors of price response program, because they appeal to different kinds of customers. We offer variable peak prices to those who can handle different prices each day. Then we offer TOU prices for those who need a more predictable schedule.

So whether one rate's better than the other, that's not really how I see it. I just see price plans as tools that offer customers different feature sets. You use them as you need them, as your supplies circumstances change and as customer tastes and preferences change. So I don't ever denigrate any type of rate. What I look at is, what do I need to offer given my supply situation as a retailer? And then I've got to stay on top of the market. I've got to do my market research.

I always remember this "Far Side" cartoon as being very apropos towards electricity pricing. You've got to leave something on the table for the subscriber, and you've got to think about the non-participant. As the company, if I eat the middle out of the daddy long legs, there's not much left for the customer, and they're not going to be happy.

Those are my comments. Thank you again for letting me participate and I'll turn it over to the next speaker.

Moderator: Thanks. That was great. Now we'll end with Speaker 4, who has been listening and I think has been thinking about how all of this has to change over the coming decades. I should point out that he is not only working for himself. He's also affiliated with Tabors Caramanis Rudkevich. Michael Caramanis has been doing all sorts of work around concepts of pricing that go beyond way beyond the sort of traditional location marginal pricing into the distribution network. Maybe in the discussion session we'll get into that a little bit.

Speaker 4.
Thank you. And thanks to my fellow panelists, who were really helpful in setting this up.

When I looked at this opportunity, what really struck me as the important question is, what tasks will pricing have to perform to realize an affordable clean energy future? If we look at where things are today, we have the situation—the two photographs both appeared in the news on the same day. They really brought home to me and I think to lots of Americans, the fact that climate impacts are neither distant nor uncertain.

This is certainly a reality that's not lost on large electric utilities. If you look at the 12 largest electric companies in the United States, with the exception of the two that already had the largest non-carbon generation footprints, all of the others have goals to reach: net zero carbon emissions at or before mid-century, oftentimes with significant interim goals.

So we can think about, then, how is the power system changing as we move through the next 10 or 20 years? I think there are three really important changes. One is, we'll continue to see an increase in the number and severity of disruptive events. Secondly, our reliance on renewable resources will increase, resources that are both variable and have correlated availability—which is, I think, a really important difference from the way we think about resource adequacy today. And, third, will see many more distributed intelligent devices, inexpensive, embedded in processors and sensors, near-ubiquitous connectivity. Advances in data analytics are all making intelligent control systems much more prevalent throughout our society and in the electric grid. This is going to include flexible demand and other kinds of DER that can shape, shift, and modulate net demand.

If we just think about where we are in terms of the way electricity is used, 37% of our electricity use in this country is for heating, cooling, ventilation, and refrigeration, all of which have thermal inertia associated with them. Then, you can look at other existing end uses. And you add into that that we are going to be adding electric vehicles, which, on the one hand, offer some significant potential flexible demand, but on the other hand, require coordination.

If you think about, for example, the relatively simple situation of a cluster of electric vehicles charging at night, this is going to reduce the overnight cooling potential of distribution transformers, with some analysis suggesting this has the potential to drastically decrease the life of those transformers. So we'll need to think about how we're coordinating EVs, in any event, as we move to a more flexible demand profile.

But, as we get these intelligent devices, we're also going to be changing the way the system has to operate. If you think about what will happen with potentially millions of intelligent devices, some analysis suggests that a city the size of San Francisco or Boston could well see in a few years 20 million intelligent devices out there interacting with the power grid. At that point, the centralized dispatch, even at a local level, of all of these devices becomes computationally intractable.

Secondly, as we get more of these intelligent systems, we'll be further reducing the effectiveness of conventional demand response. These systems will begin to anticipate when you're going to call a demand response event and they will increase their usage during the expected baseline period and maximize incentives, further undermining the credibility of those programs.

Finally, if you have lots of smart devices and you try to use a time-of-use rate, what will happen is you'll get large immediate discrete changes in demand when those prices change that can be potentially disruptive.

We try to think about pricing as really a way to communicate. It's a highly efficient way to communicate market participants' relevant marginal costs and their perceptions of marginal value within the range that matters. Then we can ask, what kinds of communication functions are going to be necessary in this affordable clean future? We've identified five with my colleagues at TCR. We're working on the first four, following what's going on in the fifth area.

One is environmental value. If you're a company, for example, in today's market trying to get to net-zero emissions, what you really ought to be concerned about is, what's the marginal emission rate associated with the resources that you have and the demand that's being served. That's quite different in some cases from simply time-balancing load and generation. Ultimately, we want to move to some sort of society-wide price on emissions. But that may be a way off. We'll see.

Resource adequacy changes in a fundamental way. Conventional peak reserve margin planning simply becomes insufficient, because you have significant generation which is both variable and has its variability that is correlated between resources. So we begin to see markets in which most of the emergency events are actually happening, not during the summer or winter peak, but during the fall and spring market periods.

We're looking at and have developed a stochastic methodology to reflect nodal adequacy on a time- and location-specific basis in market prices. We're doing that through an ARPA-E grant at TCR.

Flexible demand, I'll talk about more in a few minutes. I'll also talk about some of the applications that we see happening for our work on DMLP pricing on those. That's a topic of distribution level real-time pricing, it goes back to my time on the Ohio commission, when we actually encouraged and approved a residential distribution-level, real-time pricing market pilot. We're seeing now other kinds of applications for that kind of approach.

The last thing I mentioned, which is something that we're following, is the development of autonomous systems, including work that is beginning to look at, can we get locally generated real-time pricing looking at things like, what is the local frequency response and can we add a price signal on top of that?

As we begin to think about this future, one of the things that became readily apparent is the traditional way we have done fully distributed cost-of-service studies for rate design was really a kind of necessary fiction that resulted from our inability to use metering to associate usage with marginal costs. We're no longer in that world, in a world where we have AMI. We can move past it and begin to look at a fundamental objective of how do we create efficient and equitable pricing and rate design. From an efficiency standpoint, what our experience suggests is that LMP is really the realization of fundamental economics that says efficient prices will converge on current and expected short-run marginal costs and it represents a way of efficiently pricing electricity that we have today on the supply side of the market, but we don't take down to customers.

What we do instead is a kind of counterfactual demand response that is based on an assumption that demand in the period when we're calling an event would have been what demand was in some prior baseline period. This kind of imperfect assumption limits demand response to a limited set of discrete events and just won't remain credible as we get more distributed intelligent devices.

This brings us to looking at LMP as becoming a default compounded of a larger system of choices that enhance customer control. Speaker 2 mentioned Spain earlier, this is one example of a place where they're implementing already the 2019 EU clean energy package, which requires all utilities in the EU with more than 200,000 customers to have a market offer that follows the spot market in terms of supply pricing.

What you do when you get that is you get intelligent technologies that will then forecast and continuously adjust to expected prices, based on their users' diverse and changing requirements. And that's how you begin to integrate flexible demand and create this more level load curve. But this still leaves us with a problem in terms of rate design in the transmission and distribution are natural monopolies such that average cost is going to exceed marginal costs in most cases.

So you want to think about, from an efficiency standpoint, how do you recover these residual costs without distorting the efficient prices that are built into LMP prices? And you'll note, my language here. I'm referring to residual and marginal rather than fixed and variable. Fixed and variable are really part of the old cost-of-service framework.

So if we think about equity, most of the residual T&D costs that we have are what economists called common costs. That is, they weren't directly caused by any specific group of customers. These are the poles and wires and the operating systems that serve many customers at many different times. The most equitable and efficient way to allocate those is primarily based on equity concerns, but tempered with concerns for income elasticity, or other kinds of risks of grid defection.

If you look at the literature on equity, you end up with three types of equity that become apparent in the literature on rate design. One is allocative, or sometimes referred to as Aristotelian, equity, where what you're doing is, you're treating people in a similar way in proportion to their relevant customer characteristic of similarity or difference. Bonbright added something to that, what he called anonymous equity, and said that no ratepayer's demand should be able to be uneconomically diverted away from an incumbent.

You have then also a kind of logical corollary to all this, which is that if you allocate residual common costs in an equitable way then one consumer should not be able to change their short-term usage in production in order to shift those residual costs onto other customers.

A second equity concern is distributional equity betrayed, not unduly burden disadvantaged customers. Finally, you have a notion of transitional equity, which is really about planning and addressing customer expectations during a transition to new rates. There's some behavioral economics work about a principle of dual entitlement and community standards of fairness. There's some work that's out there that talks about the need to avoid discouraging complimentary customer investments when you change rate design.

So if we begin to look at this kind of framework, we can say some things, at least a beginning level, about what customer impacts are likely to be. One is, and there are a variety of sources that you can look at for this, that when you do flat-rate basic generation service procurement or default supply procurement, those rates tend to be higher than average retail prices. That's logical because suppliers in that world face correlated price and quantity risks, which increases supply costs relative to hourly price.

Secondly, anytime you have a uniform kWh rate, you're likely to have a regressive pricing that low-income customers tend to have less peak-oriented low shapes.

We recently did a client study looking at the AMI data for over 450,000 utility customers over a two-year period, statistically associating those customers with the income categories in those customers' nine-digit zip codes. We also separately analyze a set of AMI data for customers that were in income-qualified programs. We then try to identify the natural beneficiaries from moving to a real-time pricing regime that flowed through wholesale market prices with no change in the level or timing of customer demand.

What we found was that most customers would benefit from hourly pricing without changing their demand. In the road class that was least benefited, which was single-family, non-heating customers, a majority of those customers were still better off, including 60% of the non-heating customers with estimated incomes below $40,000 a year. In the low-income samples, 69% of the customers in single-family, non-heating class.

In the other classes, over 80% of multi-family non-heating customers were natural beneficiaries and 97% of all heating customers were natural beneficiaries. And when we added in a little bit of price elasticity, it took almost all customers to being beneficiaries at a relatively modest price elasticity rate basis. This is something that we should start by beginning to look at.

But one of the things that I want to note is that this is really quite different from some of the data that Speaker 2 showed. He was really looking at responses to differentials and rates reducing peak demand. We're now talking about what happens when we include real-time LMP as a component of the default rate.

We think this is the most cost-effective way to get flexible demand, because most customers will stay on a default time-varying rate or, as we see in Spain, an RTP rate if they're defaulted onto it. Moreover, what you've seen in Spain is that competitive LSEs begin to index their prices to the market price when the default is a real-time price. But you don't want to just put everyone on a real-time price. We're also doing that within a system of choices that is both cost effective and enhances the customer's control.

Some of the choices that they might have would be to access and get financing for smart technology that will interoperate with the available price signals and give them some apps to tell them where they are relative to their expected bill. Maybe some payment options, budget filling with an app that tracks their expected bill, high-bill payment plans, prepay, hedging options, block and index. This is basically Speaker 1's forward contract option, a maximum-price guarantee or some combination product. What Brattle has called a fixed-bill-plus product, where you basically outsource demand management to a third party and buy energy subject to specified service quality requirements.

So, as we go through this, there may also be places where we do want to begin to think about introducing DLMP pricing. The places where you would want to do that are places where you require multiparty coordination in constrained segments of the grid. An EV cluster, an islanded or fractal circuit, a microgrid. Or, longer term, where you need visibility and the ability to manage the bulk power distribution seam. DLMP prices is going to reflect marginal distribution costs, including constraints, we have to power equipment degradation and marginal losses.

As we're doing this, we then also have to think about how are we going to recover those residual choices. Given what I said earlier, it's fairly easy to see why a differentiated-access charge might be an efficient and equitable way to do that. Because most residual costs are common costs.

We have lots of options about how to do that. What would a differentiated access charge look like? It would be a monthly charge for some specified period—that period may be set contractually, subject to a customer subscription. This is a familiar model for most consumers. It's common. Another network industry is mobile phone/internet/cable TV. You subscribe to the channels or the amount of data that you want.

It's also something that's fairly common in other high-fixed, low-marginal-cost industries, such as many software packages. In many European utilities in Spain and France and Italy, part of their rates is a demand-based access charge. This is an interesting idea because demand tends to be more highly correlated with income than total usage.

If you were doing it in this country, you might end up with a subscription rate that had some overage charges and opportunities to upgrades, but the minimum subscription would be fixed for some contractual terms. But there are other ways that you can do this based on income or some location-based access charges or other ways of addressing equity concern.

What I'd like to leave you with is this question of what's needed to be able to realize an affordable and clean energy future. I've talked about it, just in the realm of pricing. We had a scenario that assumes we'll be relying significantly on variable renewable resources. There are many other dimensions to that question, but it's a question that I think we need to be asking, as we're trying to move forward into this future. So, thanks.

Moderator: Thank you. I think we're going to go into a break. After the break when we come back, we'll go into the interactive portion of this.

Discussion.

Moderator: Alright, so we're getting into the discussion part. As I said, if you have a comment, raise your hand.

Question #1: Thank you again and great presentations, everyone. Really, really interesting. Just a quick observation and then a question.

The observation, which Ashley and I were discussing, is that I generally think that Speaker 2's stated perplexity, or the general perplexity about why Speaker 2 has been at this 40 years and it's still hasn't happened I think, in large part, can be answered by the fact that, while in theory it was a good idea a few years ago, it doesn't become a really valuable idea in practice until what we're seeing happening now, which is the deployment-scale variable production, which is really the source of the value for doing all of this stuff.

And all this stuff includes, actually, deploying the technology and educating consumers about the value of participating. The idea that we shouldn't be doing this because we tried to 20 years ago and nobody did it, that just doesn't cut it. Because, 20 years ago, the situation was totally different and the value of doing this was much more marginal.

So the question goes to the premise of the session, which was pitched as dispatchable demand, but in the context of being a critical resource for the transition to a decarbonized power system. When you progress from the first presentation right on through to the last presentation, you saw progression very steadily away from the idea of dispatchable demand towards the descriptions of demand that responds to prices. Those aren't necessarily mutually exclusive, but dispatchable demand in the sense that it is treated as, in some ways, a resource in the supply curve, is, in many ways, not particularly relevant to a low-carbon transition because, historically and by design, it's a seldom-used emergency resource that almost by definition is accompanied by inconvenience to the customer that has chosen to participate.

Whereas what we're looking at in the transition is the need for a regular, perhaps even a daily, response phenomenon, and because of that needs to be invisible, in essence, to the customer in the sense that the customer continues to enjoy the energy services that they want to enjoy, in a way that they want to enjoy them.

That's not dispatchable in the traditional sense. So my question is, are we really talking about dispatch level demand here? Which is something that is accounted for in the ISO or the utility’s supply curve. Or are we talking about demand response writ much larger? Which is, in many cases perhaps, I would say from the perspective of the transition, most cases, a phenomenon that's going to manifest itself in ISOs adapting their load forecasts and LSEs adapting their daily standard load curves to reflect demand response to prices on a daily basis, in the same way that ISOs and LSEs have for 100 years had to do so, to reflect the response of demand to weather, to days of the week, to different holidays, and so on and so forth. Which it's easy to forget was an iterative adaptive process that didn't happen with the flip of a switch. So that's my question to the presenters: on the evidence of the presentations themselves, aren't we really more talking about the latter than the former?

Moderator: Anybody in particular?

Respondent 1: I'm happy to jump in. I agree with your comment. But I think, in practice, if you look at what's being done, not what we would like to have done, dispatchable demand still plays a huge role. Demand response programs that pay for demand reduction still play a huge role. I have been, for the last couple of years, trying to figure out what's that about, and I'm sure part of it is embedded rents. There are a lot of customers who are doing quite well on these programs and don't want them to change.

But I'm wondering, because there are people who I think are well-meaning, public-spirited people who still think that the sorts of demand response, dispatchable-demand programs really are important. And so I'm trying to sort that out. I'm at this point still unconvinced. As I said in my comments, I think that while I see the appeal in that last minute when you suddenly need some reduction, I also think it probably exacerbates the problem of getting to that last minute.

Respondent 2: So if I can add a couple of thoughts there. I agree. My view is the best form of demand response is the naturally occurring demand response that occurs to the movement of prices. So there could be everyday time of day rates accompanied by real-time pricing on certain days. That's the form of critical peak pricing or variable peak pricing, or it could be just hourly pricing all the time.

Some customers will take it. Some will not take it. But if enough customers take it to create a situation where, when the prices begin to rise in the wholesale market because of a shortage that is imminent or is happening, then demand will automatically begin to adjust for that. It's like the Georgia Power situation where when they first introduced RTP, the system operators didn't trust it. The utility said, “Well, we have these customers, every time the wholesale price goes above $1 per kilowatt hour load comes down by 17%.” The system operators said, “No, we cannot trust it**.** It’s not steel in the ground.” That kind of a mindset was very much there, and still is there in much of the country. But six years later, they told me that we have now convinced the system operators that it actually works. It delivers.

So this is not a curtailable rate program. This is not a narrowly defined demand response program. It is a market-driven solution to balancing demand and supply. I have always wondered why is it that other utilities haven't adopted it. It works really well. It’s for the larger customers, and if you're really large, like about one megawatt, it's hour ahead. If you're less than one megawatt, it's day ahead. They have tried to accommodate. They also put collars, ceilings, and floors for those customers who don't want full exposure.

It's still a two-stage rate. The first stage is based on your historical use and it's not affected by the margin of movement of prices. It's your Deltas that are exposed to those prices. That's one example I've admired a lot. And then, of course, there is the variable peak pricing, which OG+E has shown works for residential customers.

Interestingly, Georgia Power will not do the RTP program that it has done for the large customers for their residential customers. I have had many discussions with them, some of them might be here, too. I have asked them, why not, they said, “Well, southern comfort.” And I said, “But you should try it out. You should offer it. I have a hunch as more technologies like smart thermostats are routine presence in houses, it'll become a lot easier to accommodate them.” We will probably see what's happening in Spain and in Norway. You may have seen Tesla just announced a breakthrough in the UK with Octopus Energy. Texas has some innovations happening. New Zealand has some innovations happening for residential customers coming from retailers.

I'm optimistic that change will come. But let me make time for the other participants to comment, and I'll come back to the other issue of, why do we have such limited progress, a hundred million smart meters and only 6 million customers on any kind of smart rate? Why is the success rate 4% and the failure rate 96%? This is the United States of America, a failure rate of 96% is not impressive.

Respondent 3: If I can jump in on this, a couple things occurred to me from this question.

One is that I wonder how much of the demand response that we have, and Speaker 1 may have data on this from California, is actually really only emergency demand response? That you actually have to call an emergency event, change your operating procedures before you can access demand response. I know that in the MISO market 94% of the demand response that clears their capacity market only can be called after they call a max generation emergency and begin to change their operating procedures. That strikes me as not the way to operate a power system. That's number one.

Number two is, I pointed out all of these programs are counterfactual baseline programs which become dicier to really understand what you're getting as you get more intelligent devices.

And, number three, looking at the price-responsive demand, you're always in a situation where the operator is forecasting what demand is going to be. Demand is going to become more variable as we get more intelligent devices, whether or not you're giving them prices. But it strikes me that, as we began to move in this, operators will learn how to forecast what demand is going to be and how it will respond to changing prices. We really ought to be focusing on that. But part of how we focus on that—and this is also a question of going to the comments about how this evolves—is we really need to get some experiments in the field that actually look at what kinds of choices customers are going to make for added service over and above an RTP rate.

Are they going to buy and use the smart technology? Do they want payment plans? Do they want hedging products? Some of them will prefer just a fixed bill, letting somebody else manage their demand. But we don't really know that because we haven't run *that* kind of experiment, as opposed to the peak-demand reduction experiment. We need to do that to really understand what the potential of this is going to be as we move towards a clean energy future.

Respondent 2: If I can just make a quick footnote to what was just said, I totally support the call for doing this next generation of experiments. We have had enough of the old generation experiment. How many more time-of-use experiments do we really need? We need experiments with new technologies and with new kinds of pricing designs and perhaps some distribution-level pricing, as well. Those are the frontiers of science, so to speak, that have to be conquered. We have been enrolled in kindergarten for 100 years. Now we need to move on to the first grade. I'm in a good mood.

Moderator: Did our other panelist want to add something?

Respondent 4: I'll add something quickly. As far as the different types of demand programs, I always think about, how do I get customers to subscribe? I find load reduction programs are the dispatchable type of programs that customers, if they choose to subscribe, sometimes have different expectations than you do about if and when you will exercise that those program rights. They can become annoyed if you choose to do so.

I find them somewhat less effective than programs that work with the day-ahead market prices, where I just post prices and you make your choices accordingly. But if I dispatch a critical-peak-price program, if I call an event for today, that can annoy customers and I might lose subscription.

Then I always get in the back of my mind is, I might have CPP days, but I never see anybody offering ALP days. By that, I mean absurdly low-price days. We're very good about calling very high prices when we want customers to do something for us, but we're very reluctant to tell them, “Hey, the market has negative prices. I’ll sell it to you for a penny.” We don't do that.

Respondent 2: How often have you heard Macy's having high-price days as opposed to 50%-off days or Nordstrom having a sale? No, Nordstrom is having a peak-price day, let's rush in.

Respondent 4: That's part of the thing we talk about with our variable-peak-pricing program. We call it smart hours. In our internal debate, jokingly with the marketing and sales team, is which block of hours are these smart hours. Is it the peak prices which can go up to 40 cents and we're about 10 cents on average? Or is it the half price you get on nights and weekends? We really centered around, don't sell the program on the pain. Customers aren't interested in that. Sell it on the good stuff for them. What's in it for them? I'll stop preaching.

Questioner: I like to call that critical trough pricing, CTP.

Moderator: That's great. Maybe we'll get to there through the discussion, I do wonder whether there are two flavors here that were already discussed. One is moving from a load-following paradigm to a supply-following paradigm. Just having prices that reflect, basically, the availability or not of otherwise intermittent generation. Versus this other piece, a resource adequacy piece in some sense. The grid’s about to collapse and do we need have a more serious intervention? The costs of the system matter less than the value of lost load in some way. So anyway, I want to get to the other questions.

Question #2: This is a clarifying question for Speaker 4. In your study with the 450,000 customers looking at LMP pricing to them, was that one utility and was it in an RTO or an ISO that had a capacity market and real-time price caps?

Respondent 1: I am allowed to tell you that it was one utility in an RTO or ISO. I'm not allowed to tell you more than that, by the client.

Questioner: The reason I'm asking is, would the study hold true in a place like Texas, where you don't have a capacity market that oversupplies capacity and, therefore, keeps real-time prices relatively low on top of that, with low price caps, versus a place like ERCOT where prices could go very, very high?

Respondent 1: Well, I can tell you that the comparison was between a rate with a default supply price that was competitively procured, and the real-time price—one would expect those competitive suppliers to be building in their correlated price and quantity risks from buying in the wholesale market for the default supply price. So that was the comparison.

Questioner: OK. Let me then just throw this out to the panel. Where there are questions about why aren’t customers doing this. The global question. I was just looking at current prices and it's not far off mine. In a place like California, where you have 20¢ on the cheap side and 40¢ on the high side versus my current rate, which is 8.6¢ all-in, including T&D charges. In low-cost states, why do customers want to move?

Respondent 2: By the way, the high side is 50¢ here.

Questioner: 50, OK.

Respondent 1: One of the things we don't know is to what extent price elasticity matters at very low prices. This is part of why one would do experiments. In Texas, you still have those $9,000-megawatt-hour price days. So the question is, what would people be willing to do to be able to manage that risk? They might decide that there are different ways to manage that risk than a flat price. But this is an experimental question where we need to run experiments. I know ERCOT has identified that they get some demand response just from the pricing that they have in their retail market on those very expensive days.

Respondent 2: If I can add, Puget Sound Energy, just around the time of the California energy crisis, rolled out a time-of-use rate, which had a differential of 1.3:1. The peak price was 30% higher than the off-peak price. They got a 5% reduction in peak demand, even with low prices. More recently, Portland General and Seattle City Light and Smart**,** Smart has lower prices then PG&E, and Public Service Company of Colorado and Fort Collins in Colorado—all of them have much lower prices than California's prices. They have all found the response behavior that I described to be generally true. If the price ratio is 2:1, you get a 5% reduction in peak. If the ratio is 5:1, you got a 13% reduction in peak. The price level does not play as big a role, intuitively, as you would think it would. People respond to the savings opportunities, regardless.

Nobody in the northwest has ever said to me, their rate is low. They want it to be even lower. So if you give them a savings opportunity, even with their lower rate, they still respond. Otherwise, energy efficiency would not be there in the northwest. It's a big deal in the northwest.

Respondent 1: I'll say one other thing. That is as you got intelligent technologies, those technologies will seek to optimize even over relatively low price differentials once the technology is in place. So we would expect to see some greater response in an intelligent system where it didn't depend on customers looking at the differential on an event basis.

Respondent 2: Exactly. Hydro-Québec has some of the lowest rates. They did a critical peak pricing experiment a couple of years ago in the winter peaking climate. Even there, what you're describing came to pass. People shop around for everything in their life. Why would they not shop around for a better electric bill? That's the part I can never grasp.

Then the issue comes up of low-income customers, that they cannot respond. To them, the marginal value of $1 saved is even higher than it is for somebody who has a lot more money. So the LMI customers are often singled out as a primary reason of concern why these rates should not be offered.

In California, that has been the biggest obstacle for 20 years. Finally, they have relented and it's going to happen. But it took 20 years to convince TURN, the group that represents the low-income customers. Mark Toney is the head, a sociologist by training. I've had many debates with him. His view is these folks are not rational. They're not educated, they cannot understand what's good for them and what's bad for them. I said that's being very patronizing. They cross the street when the traffic light is green, as opposed to red. Basically, this patronizing approach, this fear of the unknown, has blocked progress in much of the US for four decades.

Respondent 3: Can I just jump in? On the point, which I think is incredibly important, which is that as we get more smart devices and smart response, the benefits to getting prices right go up, but the costs of getting prices wrong also go up. I think that Jim Bushnell and I, in our paper on 20 years of restructuring, talked about regulatory arbitrage, which in the past has not been that big a problem because people haven't had much ability to respond to bad prices.

But we're now seeing it. Much of the rooftop solar industry in California is regulatory arbitrage, from net energy metering and very high retail prices. We're seeing it in demand charges now, as consultants teach the customers how to shave their demand charges through socially inefficient investments. So I think as devices get smarter, as optimization gets better. The cost to not getting this right is going to go up.

Moderator: Great. Thanks. I'm going to move on.

Question #3: Hi, everybody. I wanted to pull together a couple themes and have a question based on what we see in some of the markets. One of the themes is what Bill Hogan has talked about in a lot of these HEPG sessions, the importance of scarcity pricing in wholesale electricity markets. Bill really likes scarcity pricing. FERC thinks it's a good thing. Several of the ISOs think it's a good thing.

A second thing is that FERC recently has had this whole proceeding on the interaction of state policies with wholesale markets, and it was all about the capacity markets. I actually think that this is the wrong focus and there's a real need for a pretty high priority FERC initiative to address a very big market design flaw with respect to state policies which are, basically, unintentionally suppressing wholesale market prices. I'm talking about the scarcity prices, through the state sponsored DR programs.

We participate a lot in the spot market, in the wholesale market, and any of the market participants who do see this taking place. It happens in the northeast every summer, where these state-sponsored LDC programs basically kick in prior to the ISO visible DR programs that are intended to trigger the scarcity. You can get 5-8% of reserves from these LDC DR programs, which the ISO simply sees as missing load.

As one example, in the Maryland program residential customers who are enrolled—and I think it's a very subscribed program and it's a big success—but those customers are receiving $1,250 per megawatt hour for curtailing at exactly the time when PJM's prices are maybe $50. But for all the LDC DR programs, prices would be at scarcity levels. Basically what I'm seeing, or from our perspective, we think that the current investments in demand response aren't well integrated into wholesale price formation at all.

One of the advantages of doing it actually would be if the ISOs could rely on customers to respond flexibly to price signals, you wouldn't really need capacity markets to keep the lights on. I think ERCOT has shown that to some extent. So I think we need a technical conference or a NOPR on it to explore more, because there's a lot of things you could do, such as adding to reserves the amount of the LDC DR response level, in order to at least get the prices approximately right.

I just think that the current FERC policies, speaking particularly about where the reliance on capacity markets, and also to some extent Order 745, are really counterproductive in terms of where we need to go in the future.

So I don't know what my question is, but do we need a FERC technical conference on that? How important is this issue?

Moderator: Does anybody want to react? I'm happy to. I was actually a little confused about the comment about demand response programs compensating participants at the LDC level at prices that far exceed the equivalent wholesale prices. I guess I'm curious whether that doesn't necessarily mean that they're being overcompensated.

Questioner: It just means that the wholesale prices are too low, which exacerbates the missing money problem and then says, "Oh, we need to rely on capacity markets to ensure this." Then you get the demand response supplier, the people who are doing demand response, all end up getting addicted to capacity market payments, rather than actually being responsive in the market when they're actually needed.

Respondent 1: I'll make a quick comment. I was there in the room where that decision was made to go with that program. There was an experiment with peak time rebates that BGE had done and critical peak pricing and time-of-use rate. It turned out that the rates for design—the CPP and the PTR rates—have the same opportunity cost for the customer.

The experiments show that the customers did respond equivalently to those two rates. I certainly proposed doing the CPP rate, assuming it was market based, but the public pressure of having a higher critical peak price was much more in the client's mind then doing the rebate, which comes across as a no-lose proposition for the customers. If you don't do anything you pay the standard rate, which I think was around 14¢ or something—if you do something, you're going to earn a reward. They went ahead with that and it has proven to be very popular with customers. 88% of them are on the rate, and they're saving varying amounts of money based on a baseline. The baseline has all the issues that we are all very well aware of but, in general, other than economists, people don't seem to be too concerned about overpayment.

I don't know why that is the case. But that's the kind of subsidy that is not frowned upon. It is just smiled at. So life was good but then FERC changed the rules and the capacity equivalence thing has come in. Now it's becoming a challenge for both Pepco and BGE on how they will continue to make those payments. If PJM is not going to make those payments to them, they have nothing to pass on.

That my comment. I don't know more about it, but that's from just some of the optics of rate design the PTR seems so attractive, and if you can lock in a capacity payment, nothing like it.

Questioner: I just want to also clarify that I'm not critical of the programs themselves. My concern is the unintended consequences of the impact of these programs on wholesale market prices, such that you spend all this effort designing scarcity prices but then you have LDC programs that are outside the purview of the ISO that are coming in, knocking down the demand at exactly the time and actually rewarding them with very high prices, never actually triggering the scarcity pricing, which then has the all the other negative consequences.

Moderator: And it's interesting. You're asking how much of decision-making should really be incentivized purely by the wholesale price, as opposed to other structures. For example, I suspect a lot of LDCs have extremely aggressive energy efficiency programs that are not at all incentivized by wholesale prices ever, but they have, of course, an impact on the levels that you need for resource adequacy.

Questioner: What's interesting is that the ISOs are always able to measure. I'm not necessarily talking about energy efficiency programs and those kinds of things. The ISOs know, at least within a day, how much the LDC programs actually responded. They roughly have an estimate and they could, if FERC insisted that they do it, they could actually take an estimate of the amount of retail demand response that's taking place, that estimate and add it to reserves in order to ensure that the prices are approximately right. So you don't get this price-suppression effect.

Now, in some cases, some of the states view that as a positive attribute of these programs—that we're actually benefiting all the customers across our load, because we have these programs that are basically preventing us from having very high prices in the summer. But it's really tied into the whole energy-only versus capacity discussion that you have with respect to the market design choices you have in ERCOT versus the other markets. I would argue that states are paying way more from this over-reliance on capacity markets and, furthermore, not getting us where we need to go in terms of longer-term resiliency integration of demand response into the market, figuring out all of the utility-of-the-future efforts that I think everybody here is very supportive of. But the market design isn't supportive of it. So we never get there.

Moderator: I know I'm responsible for prolonging the conversation, with a bunch of other people still in line. Next question.

Question #4: Where I work, we deal with a lot of questions from demand response providers in California about integrating various machine learning and smart devices into their platforms.

I think what I've heard from them is that the big untapped resource in demand response or are EVs. That's no surprise. And, of course, integrating EVs has been a constant challenge. And so I think building on the last question, I think, to the panelists—Speaker 1, I heard you mention Ohm Connect, so and maybe you're the right one. But, how do states design regulatory structures that enable these local areas to take advantage of the influx of smart devices and machine learning?

I think California has been very successful in attracting innovation, partly because there's a program, people can register, businesses can try, and they can get on. I would love to hear, is that the goal, to enable new devices and EVs? And, if so, how do we get there?

Respondent 1: I think that that was part of my comment about letting 1,000 flowers bloom. I think that what we want to do is design platforms that do enable these startups and demand response companies and innovators to get rewarded appropriately. I do worry. I was commenting about trying to push this out of the ISO/RTO down to the load-serving entities.

There is this additional problem if the load-serving entities are large, and it's related to what was just said, they may have the wrong incentives—in fact, even overpay for demand reduction—in order to suppress prices, monopsony sort of behavior. But I think, setting that aside, if we can really push it down to these firms and get the right incentives, I think that's what we should be aiming for, so that we do have the entrepreneurs who are actually trying this stuff have the right incentives.

I have been, in the past, pretty skeptical of a lot of the aggregators and demand response providers, because I thought they weren't facing the right incentives, it was basically regulatory arbitrage. But at the same time, if we can get the right incentives and they actually are responding to that, as I was saying, I think that's where we get the good effect of this optimization ability because they're responding to the right prices.

Respondent 2: If I can comment as a customer. So I have on the Ohm Connect program. They have a device, it costs $25. I can put it on one appliance. And when they send me a signal between 7-8pm or 8-9pm, that device will be turned off. The problem is the big load in my house is the electric car. That's the biggest load and it's not plugged in, I charge it between midnight-6am.

It's never calling the event during that time. And the other big load is the air conditioner. It’s too big of a load for that device. So I am on Ohm Connect, I’ve been on it for a year, I get those messages. My wife doesn't want me to plug in that device into any appliance. So that's sort of the end of the story there, but I do pay attention to it.

And in terms of the other comment, utilities have an incentive to overpay. Let me tell you what they paid me for my direct load control air conditioner program. I was on it for three years. They paid me $25 one-time payment for unlimited interruptions. Is that overpaying or underpaying?

Respondent 1: I will agree with you. They also paid me $25.

Respondent 2: There was equity Aristotelian.

Respondent 1: Let me just point out that the program that you're on might not be well designed. In fact, I think it's probably not, because what the program should be doing is not adjusting a plug but adjusting your thermostat. If the program were adjusting your thermostat—there are firms out there that know how to do this, and I think Ohm Connect is one of them—they could actually have a very substantial effect with a very small notice, a very small amount of discomfort or problems from the customer, changing your air conditioning setting by a couple degrees.

Questioner: They’re your “auto Ohms,” and that probably does need some adjustment.

Respondent 2: Yeah, the thermostat I have has a demand response feature built in. But I am not in a demand response program. I’m on a time-of-use rate. So I have adjusted it to follow the time-of-use rate. It is doing something, but it's not dynamically doing it. And I said to them, “Can I replace it with a Nest or an ecobee?” But they said, “Oh, we have a five-stage compressor and that will be a two stage. So you're going to lose out.” So there are technology barriers. It's not an easy solution today.

And then comes this whole issue of vehicle to grid, which hasn't come up yet. But so many people are excited about it. It requires you to keep your car plugged in. At any moment in time, they’re going to take the power from the car and transport it to the grid. Well, I don't want that to be done because I may need the car at some point, and they may overdrain my battery. Plus, Tesla won't even allow it. So it's going to be dead on arrival.

But it seems to come up a lot. I think more needs to be done to improve the technology interface. Technology is not quite there today. That's my first-hand impression.

Respondent 1: I think that's why you set up these incentives, so that firms have the incentive to create those interfaces. We shouldn't try to design the future from a regulatory point of view, we should try to create the platforms that allow firms to design the future.

Respondent 3: I would agree with that, that creating the platforms is I think a critical element. And one of the things that can happen on that platform is the platform provider can certify whether or not particular technologies will interface with the price signal, and what capabilities they have, and make that clear to the customer so that they're able to make rational choices.

Questioner: Thanks to you all.

Moderator: Next.

Questioner: Thanks to our panelists. I just thought this is one of the most interesting discussions. Of course, for all of us who have been involved with this for years, if not decades, it's a very frustrating topic. That doesn't mean it doesn’t need to continue to be discussed as widely as possible. The relative difference between wholesale and retail prices in the electric industry is, as far as I've ever been able to think about, a multiple of any other industry in anything. I'm not even aware of any industry where there's such a discrepancy between wholesale prices and retail prices.

So it's no surprise that when that happens, we have all kinds of anomalous results and inefficient activities, and then we have what I think of band-aids like demand response that tries to make the best of a really bad situation.

I just wanted to ask a couple of questions. First of all, in terms of demand response, how much dispatchability do we really need, just coming from the demand side? It seems to me that when you're talking about minute by minute that, just as with supply resources, we have these ancillary services, the reserves and regulation, that accommodate minute to minute. It’s really a question of more hour to hour. I'm not sure I understand the problem in that regard, so a little discussion of that.

I have one other question, it goes to the EV question. And, yes, I understand about the concern again about demand, where the utility would actually take control. But if we were instead on a system of dynamic pricing, then the user gets to decide how to respond to the prices in terms of when to charge and when to discharge. AI will be able to assist in that, of course, and it seems to me that the EV is going to be the ultimate in flexible resource, both load and resource.

My question in that regard is, will EVs be the last straw that we need to have in order to finally get something like dynamic pricing in place on a wider scale. Thanks.

Respondent 1: I will jump in and say, on the dispatchability question that we don't know how much dispatchability we need because we've never really gone down the road of the alternatives. My guess is that if we took dynamic pricing really seriously, we would find that we need a whole lot less dispatchability. We'd have to get through this intermediate period where the grid operators have to be willing to deal with the fact that they don't have this one tool in their toolbox.

I don't think we just tell them you can count on a certain amount of demand response, what we tell them is “Look, the load curve is getting a lot flatter, and you're running into less of this need for dispatchability.” I think that's what we'd find. But, unfortunately, we have very little experience at it because, as was being said, it's much easier to sell payments for demand reduction than it is to sell dynamic pricing. Apparently, that's even true with large, sophisticated industrial customers. And I think the reason is the way we have designed those programs for them. They're just huge rents that they're earning. Even if it's less efficient and even if they know it's less efficient, they're not going to just hand back those rents that are in the current design.

Respondent 2: Yeah, that's very true. Actually, I have an example from Canada in Nova Scotia, there is a 200-megawatt pulp and paper mill that was on a real-time pricing program for seven years. It was really an economic development rate. They said they'd much rather have a flat rate with a discount, and they are more than willing to turn over the control of their operation to the utility for a certain number of hours a year.

So they took an RTP program and reinvented it as a demand response program. They wanted me to support that case. It was a complicated conversation, if you will.

But let me briefly comment on the EV issue again. Being in this business and being excited about everything new that happens, I signed on to a program called Flex Charging for my electric car. One of my former colleagues worked at this company and said, “Oh, you would be so much more.” So then I downloaded the app. I gave all of my information about the car, including the VIN number to the app. Then I noticed that strange things were happening at night.

The car was not plugged in. I would only plug it in when I was charging it on a weekly basis. But it was losing power. It was losing range, just while parked in the garage. So I reached out and it turned out they were polling the car, just to check in on it. And every time they would poll the car, it would wake up and it would lose charge. I reached out to Tesla. I spent so much time as a detective trying to figure out who's stealing my power. I'm not driving the car—we're in a pandemic, it stays in the garage, and it's losing its charge.

Finally, it turned out they were pinging the car. I said, “I want to stop this or change your password.” That's what Tesla said to me. So I changed my password. They would no longer ping me. And then, by the way, I said to them, “What do you do that I couldn't do myself?” They said, “We know when to charge it.” I said, “I know a time-of-use rate. I plug it in at midnight, and I set the timer. So it goes from midnight-6am.” They said, “This is not for you. You already know. It's for the other people who don't know how it works.”

OK. So fast forward. All kinds of things happened. One day, Tesla keeps asking me every two months to change the password. It drives me crazy. One day, I changed it back to the original password. That day, I lost five kilowatt hours and I couldn't figure out what happened. So I reached out to the Flex Charging person. He said, “Oh, we were repeatedly pinging your car again. Did you change your password?” I said, “Yes, I did.” He said, “Thank you. We went to fix the bug.” So that's smart charging. Highway robbery.

Moderator: Anybody else want to comment on that from the panel?

Let's move on.

Question #5: My question was to whittle it down, back to almost one aspect of the conceptual element. And then weave in a couple little side conversations that some emails have had in a side chain here.

First off, are we really trying to dispatch demand and the nature of so having demand in the supply or demand side and everything.

It seems like to the basic question of whether just exposure to dynamic pricing would work, and any potential shortcomings on that front, a lot of the stuff that seemed to be identified today and in previous work. A lot of it just seemed to boil down to overcoming transactions costs and information asymmetries.

We did a paper this week that got into why AMI infrastructure hasn't been utilized very efficiently to date. A lot of that came down to data access. And then coming down to different aspects of overcoming different elements of transactions costs. So I wonder if that's a way that we can start framing some elements of this.

Then, to the other point of, if you do see the dynamic pricing exposure element of this, how big of an issue is it for any potential principal agent problems in cost of service jurisdictions, where, even if you see right now with even existing pricing structures. In some of the RTOs, you already see some uneconomic behavior participation with that in some of those entities and a lot of artificial suppression of different demands-side products in the creativity. Whereas, you see the competitive retailers, when they get good information, start to develop differentiated reliability products.

So my question is, how much can we fit it into some of those bins and then maybe start to dissect under which paradigms what different types of approaches would work?

Moderator: Volunteers?

Respondent 1: I'm not sure whether I am fully grasping your question. But I think we end up, particularly in cost-of-service jurisdictions, with a kind of historical paradigm that doesn't really work in this new environment.

We end up thinking about cost-of-service studies actually being related to costs that customers cause when, for the most part, these are common costs that are not being caused by individual customers. We oftentimes end up thinking about or having people cite to us Bonbright's eight or 10 principles which are not, in fact, his principles, that's the title of his book and he says these do not really warrant somebody calling them principles if you actually read the chapter.

So, it is a lot of being stuck in what I would call formerly necessary fictions. I think whether we're in a competitive jurisdiction or a regulated jurisdiction, we're going to need to move beyond that model and actually think about what's going to be required going forward.

It's not just the regulator. I think there's also a similar kind of inertia on the utility side to some degree, because utilities are used to earning their returns on capital investment. We set that up in the way we develop regulatory systems, it might be better if we had a **todex** regulatory system that simply said you're going to be able to capitalize *x* percent of your revenue and earn a return.

But we have these kinds of historical models, which I think they're based in part about information asymmetries. But from a regulatory standpoint, as a former regulator, I think in some ways regulators have, for lack of a better word, a lot of chutzpah to say that we know better than the customer what rates the customer wants, and we're going to give you a uniform flat rate, whether that would be what you choose or not.

We do it because it's historical. We do it because it's easy. In some ways, I think, in the regulatory community we need to get out of our own way and instead think about how do we give customers choices that give them real control over their bill and see where that goes.

Questioner: That was really helpful. On the other aspect of my question—sorry if I framed it a little bit vague—I'm going to more the transactions costs and information deficiency side. One thing is that, even in the Texas model—unfortunately, Beth Garza couldn't make it here today—but even on that side, we see some indicators of evidence in Texas where you have demand occurring when prices are low, above what we would think the value of lost load would be for that particular customer. Which starts to raise certain questions about why that would be happening. To me, that would suggest that we maybe have some transactions cost issue on the aspect of information side. Whereas, when you look at, someone was noticing the behavior of some of the industrials down in Texas, you'll see a lot of demand reduction around the transmission charge periods. The coincident peak periods.

Because they can anticipate that, and they can conceptualize automatically what that avoided cost is. And then, boom, do it. Whereas what we see in the scarcity pricing component of it, I saw it at ELCON a lot last year there was an issue of the predictability of the pricing element and the inability to pre-position enough load in advance. And so, while the industrials were talking to ERCOT about not just the dispatch element but getting built into the unit commitment process more.

So it seems like a lot of that gets into the coordination aspect of the transactive elements of it. So that was a little bit more of my nature of that question for it takes to kind of weigh in on.

Respondent 1: Let me just comment on one other thing that you mentioned there. Whether you're talking about a capacity market or an operating resource demand curve, these are things that are being set administratively and are being set on a market-wide basis.

If you're thinking about a future with lots of variable and correlated renewable output that really ought to be nodal, it ought to be time specific and in ought to appear in a price that is a resource adequacy price that customers have an opportunity to respond to. That's what we're trying to get at with some of my colleagues' work on the stochastic nodal adequacy platform is to really try to find the way and do the math, so that we can put that component in an hourly nodal price, rather than in something that is administratively set.

I think that's the direction we need to go. We're in the early stages of a three-year ARPA-E project. So it will be a little while before we get there. But I think that's directionally where some of the ISOs are really interested in moving.

Moderator: Great. Let's move on.

Question #6: All right. Thank you very much. I've been taking notes here and I've got multiple questions. So I'll try to frame it in a way that that makes a lot of sense for folks.

Just a reminder for folks, I'm here in the Southwest Power Pool and we've seen explosive growth in the price-responsive demand response in SPP. In 2018, there were zero megawatts. In 2019, there were .3 megawatts. And, in 2020, there are 11.6 megawatts of price-responsive demand response in the market.

You can see it's very explosive in terms of how much we've increased over the last couple years. But, from my time in Cal ISO, it was not that different. What was in the market was in the 10s of megawatts. Now, obviously the CPC had their programs and they had thousands of megawatts for resource adequacy. So this is connecting, I think, to what was said earlier—you've got a lot of programs. We heard from Speaker 3 earlier in OG+E, where there are significant amounts of programs and customers that are signed up. But we're not seeing that translate into the RTO programs that they do have.

With that, I think that that gets to dispatching demand outside the model, and what that can result in is effects price. It also affects reliability. We do see instances where wind has self-dispatched and it creates oscillations on transmission lines. So things that are not in the model can create some operational challenges. Given the low levels of demand response we see, at least in the market, it's not having an effect today.

My question really is, how do we get to where we are today in terms of having programs that do exist? At some point, as was said, maybe we need to come in here and do a technical conference. I'm just wondering, what are some of the steps that our speakers think. Are there things that SPP can do to help capture more of those demand response megawatts in these price-responsive programs? Thank you.

Respondent 1: Can I ask a clarifying question, please? Just to make sure I understand your question. So you mentioned 11 megawatts, I believe, of demand response. If you could tell us what kind of demand response that is, and, secondly, don't you think it would be easier if we just transmitted the wholesale prices to retail customers? That takes all of this elaborate jigsaw puzzle stuff out of it, as to which model are we in, which model are we not in and who's controlling this part of the engine of the airplane and who's controlling that part of the engine of that airplane.

Questioner: The two points I would make to there is, what types of programs, these are primarily [UNINTELLIGIBLE] such as the aggregated stores across the footprint type of thing.

But I see your question and it's a good one, because there is the concern of reliability, in the sense that if the operator doesn't know what's going to happen, let's say on a transmission constraint. We saw this when you see wind resources that were non-dispatchable dispatching themselves. You can see instances of, let's say, oscillations on transmission lines where you may have a situation where, oh, we have a big violation here we need an action.

So then you get an action and then the price collapses. And then it stops and then it comes back up. You can end up with these weird swings. Then the operator has had enough of it and they say, "Fine, we're going to take out-of-market actions to stop that type of issue from creating concerns." What I would be concerned about is if the operator doesn't know what's going on, they may in fact take actions that counteract what your demand is trying to do. That's the worst of all worlds. In some ways that the operator doesn't have insights they may take actions that are either exacerbating or countering what they're seeing on the other end. I'd be curious to see what the group's responses are to these points.

Respondent 2: Can I ask one other clarifying question? Are these demand response programs that you generally have in SPP are those SPP programs? Or are those state and utility programs? To the extent you're seeing state and utility programs, are you seeing state regulatory authorities that are opting out under Order 719 from offering demand response or certain types of demand response into the wholesale market?

Questioner: My understanding is that none of them are state programs. These are essentially an aggregator that's working directly with particular customers to bring these programs to the RTO level.

Moderator: All right, now that you've all asked clarifying questions. Who wants to jump in and try and answer?

Respondent 3: I will share some of how we view it or how I view it at OG+E. And that is, we manage our peak. We still are responsible for providing enough resources to cover our load plus a reserve margin. So we dispatch internally our variable peak pricing program against our highest load days.

So SPP sees reduced load at OG+E than what it normally would. It's just part of our normal operation, if you will. Our peaks are not as high, by probably 100-150 megawatts just due to our VPP program. Yes, there's a little bit of disconnect probably between OG+E's peak and the SPP peak. However, I'm pretty sure we all peak summer weekday afternoons and our response from our customers is fairly broad. So it works well, from our perspective.

That's how we operate it that, very practically. I think it captures much of the benefit, but it does not require that we participate in the SPP profit programs. We manage our own.

Respondent 4: Can I just ask, what is the barrier? I understand why you might do that if you weren't part of a market. But if you are, why wouldn't you manage to the market incentives, rather than feeling that you have to balance internally?

Respondent 3: Well, remember, SPP is, the way we think of it, is an energy-only market. We're still required to come in with our full plate of resources to cover expected load plus a reserve margin. Currently, I think it's about 12%. We're responsible for acquiring resources and bringing them to the market in order to play. We can't do it if we don't.

Questioner: If you capture the capacity to meet your requirement, why not offer that into the market to optimize those decisions for you?

Respondent 4: That was basically the gist of my question.

Respondent 3: Well, we think we do currently, but where we're not participating in the wholesale market, I will share a story of something that happened in 2017 in Arkansas. We had thought our variable peak pricing program needed some adjustment. The prices were disconnecting a little bit too much and we recalibrated them. We started seeing higher prices. We had a reaction from the market. We had a reaction from outside the market. We had customers as far as Pennsylvania screaming bloody murder about why our prices were so high.

Our regulator didn't appreciate that. So we looked at it, we found there was a small error, but it really wasn't substantial, and we had to look to find something. But the point was that when we had a few more days of critical prices customers became annoyed, so we looked to dispatch the minimum number of high prices or critical prices that we need to manage our resource requirements.

I find customers get very annoyed when you post critical prices to them. They can respond and they will take it for a day or two. But then they become annoyed.

Respondent 1: I can add a footnote there. So I was on PG&E’s critical peak pricing program and also their direct load control program for the maximum possible impact. It was a heat wave a few years back. They're called events, three days in a row. Wednesday, Thursday and Friday. On Friday, I was working from home and the temperature had risen by six degrees. Two degrees every day. It was rising and so my wife came to me and she said, “I think you put us on the program I told you not to put us on.” I said, “It was an experiment.” She said, “OK, I want you to get us off the program.” I said, “You can call this phone number.” She said, “No, I'll stand here. You call the number.”

So I called the number. I called the critical peak pricing person first. And they said, “No, no. The problem is with direct load control, it’s not the price. It is the technology.” So I said, “Can you transfer me over?” They said, “No, you have to call this other number.”

So I called the other number and the person who picked up the phone, he said, “Well, the program just ended. It's 7pm. I said, “Maybe you're in Texas. I'm here and it's 5pm and the program is still going on. So I want you to end the program.” And the person said, “OK, I'll end it just for today.” I said, “No, she's standing here. She wants me to get out of the program.”

I said, “OK.” “Are you sure?” I said, “I'm absolutely sure.” And then I said, “Can you remove that device, which is on my compressor, just to make sure it doesn't accidentally come on” “Oh, no, that would be $100. You're willing to pay $100? I said, “No.”

At some point, the air condition to was changed, that device left the house. Who knows where it is, but I've heard the opinion in the dump yard.

Moderator: Next question.

***Question** #7*: Thanks. I want to go back to some terminology that Speaker 1 was using when talking about getting incentives right and creating a platform where creative entrepreneurs can come in and help people manage their load.

My question is, if you want to call those entrepreneurs the app creators, who's a customer for what the app creators do, and can the utilities be that run the platform, can they also create the apps? Where are the lines there?

Respondent 1: That's an interesting question. I wonder. Rate-of-return regulated utilities tend not to have the best incentives, so I guess I'm a little hesitant to think that they're going to be the ones who are going to be the real innovators here. I'm more inclined to think that we want to set up markets that put those prices out there. My guess, but maybe I'm just jaded from the California regulatory experience, is that the regulators are going to be so slow and so hesitant that that's not where the innovation is going to come from.

I think the most we can practically ask of the regulatory side is getting the prices roughly right and avoiding the new offerings that get prices massively wrong. I would put demand charges as probably one of the big problems of that sort. Then, allowing other independent entrepreneurs to respond to those prices.

Where exactly those lines are drawn, and particularly when you then start talking about load-serving entities that are not IOUs versus independents. Ohm Connect is not a load-serving entity. They run this separate program that sells into the demand response program. I'm not very comfortable with that. I have been in meetings with them and said, “Why isn't there just a load-serving entity that does what you do? That provides it. The answer in California is you can't. Retail choice is frozen. You can only do it this way.

So I think breaking down those barriers to give the opportunity to do it as a load-serving entity would be the most attractive way to do this. I think the track record on the IOU side is pretty clear. There are a few outliers like Georgia Power. And then there's the vast majority who have not been very innovative. And OG+E.

Respondent 2: A question. I think this is a fundamental issue and one that I run into in every state where I've worked, every Canadian province, as well, and overseas. Utilities are trying their best, but it's not good enough for the customer. The customer is way ahead of the utilities these days. The technologies, the apps and so on.

Again, a personal example, when I switched to solar and storage and an EV, I wanted to know what is the best rate for me, among the many the PG&E offers, for me to pick. And so I call them. And the person said to me, “I only have two of your three technologies. So I cannot really be sure what to suggest to you because your load shape, your new load shape, doesn't exist yet.” I said, “Well, I can tell you the size of my panels and the car and the storage, and you should be able to simulate what my future load is going to be.” And she said, “We have asked management for a budget to do exactly what you're saying. They won't approve the budget.” I said, “It's not such a sophisticated problem. I'm sure Google or Facebook or any of those companies can easily develop such a capability.”

But it hasn't happened, and I doubt it will happen. So there is a market failure within the regulated model to give customers what they need. Are you optimistic that it will change? Do you think we have to step outside of the regulated model?

Respondent 1: I'm not optimistic it will occur within the regulated model**.** I'm not optimistic it will come from the IOUs or the regulators. That’s why we need to, rather than having them be the one modeling your new load profile, have third parties that, at the least, can step in and help at that margin. I would prefer to see them actually behave as LSEs. California is in this unusual place, which is that we are about to have half our load served by CCAs, who are all for competing with the IOUs, and that's great.

But I'm not sure why we shouldn't go further than that and have other participants competing with them, including private LSEs who can come in and look at your solar panels and car and so forth and say, “We can design a rate for you.” Or, “We can just put you on a real-time rate with a forward contract that minimizes fluctuations.”

Now, there are a whole lot of customers who don't want that, and who don't understand it. That's fine. Residential might not be the best place to be doing this, or at least for many residents. But there are some who are. You're obviously way out on the tail of sophistication—but for those people, if there are enough of them—I would expect their Ohm Connect type companies that can design that.

Respondent 2: So in a sense, if I can ask just one final question very quickly. What you're actually raising is a very good issue, which is retail-choice. California doesn't have retail choice. It's frozen because of the crisis that occurred. Do you think it might be worth revisiting it?

Respondent 1: There's a part of me that says yes. But then I look at Texas, and Texas is, by and large, been a disappointment on the retail choice side. There are plenty of firms, but they all offer the same products. So I'm not sure. I have learned to be a little less confident that the market is going to get everything right. But certainly we haven't seen as much of the sort of dynamic pricing and those sorts of smart thermostats, and so forth, as I thought we would see in Texas, where there's tremendous opportunity.

Then I am reminded, I'll tell you a personal anecdote of the executive for Gulf Power, who, when I gave a talk in Florida in 2003, said, “We've been doing critical peak pricing with smart programmable communicating thermostats for years. And when you sign up for our CPP, you tell us what temperature you want your thermostat set to.” I thought we would see that take a much bigger hold in direct access states, particularly Texas, than it really has.

Respondent 3: I want to respond to that and also to the initial question.

So I noticed that in the chat, and this strikes me as what I remember, someone who's in Texas has posted that there's three gigawatts of price-based demand response in the ERCOT market, presumably as a result of retail choice.

My other response would be to say that when Texas started everybody was still offering flat rates and it became a price-to-beat competition. I think one of the things that will be interesting—and we see a little bit of evidence, but I don't know enough yet from Spain—is if you start with a default dynamic price, does that change and how much does it change the nature of the competition?

Because people then are not simply in a price-to-beat mode, but they're looking to supply services. I think that's a question that we need to find out the answer for, as we do experiments as we see what happens in places like Spain.

Respondent 1: I think that's a great point. When you set up default matter and when you when you set up a default that is flat rate, I think that impedes the sort of innovation.

I can't see the chat. I'm still on my phone, but that comment. I wonder of that three gigawatts, how much of that is residential? Maybe it's that residential isn't going to be the place that we get a lot of this response. Maybe the real opportunity is more at commercial-industrial. Certainly Georgia Power said it has done it at commercial-industrial and they've done it incredibly successfully.

Respondent 3: Although I would add that when Speaker 2 and his colleagues did the flexible demand potential study for Northern States Power, and I think it's probably reflective of the national study as well, but a very large chunk of that was residential smart thermostats.

Respondent 1: The issue is marketing. Yes, it's easy to technically say, “Boy, there's a lot of opportunity.” I've been told this about lots of energy efficiency. There are lots of opportunities, but the marketing of it and customer acquisition just makes it uneconomic. Maybe that doing this on a customer-by-customer basis at retail for residential just isn't going to pencil out.

Respondent 2: ERCOT tells me that they have about half a million customers now on some kind of time-varying rate from those

300 or so retailers that are out there. And most of them are either on a time-of-use rate or in a peak-time rebate. But a few are on real-time pricing so—

Respondent 1: Are you sure they're not counting free weekends as a time-varying rate? My understanding is that is the most popular time-varying rate in Texas.

Respondent 2: I'm not excited about what they have, but that's at least better than nothing, right?

Respondent 3: Well, in the chat it said that the three gigawatts, very little of it is residential. But I'm going secondhand. At some point, I do want to get back to the initial question.

Commenter: I'm not totally sure that's true. Part of the problem is that the details of all these programs are not generally public, because they're offered by competitive load-serving entities that don't really want to disclose very much about their success or lack of success.

With respect to at least the price-responsive piece, there are significant number of residential customers, because some of the participants are competitive load-serving entities. Now, they may be doing it because they also use it to minimize their transmission costs**.** The 4CP problem. Nevertheless, what they've done is aggregated their customers, which would be both commercial as well as residential. And, by the way, the co-ops and the munis are getting in that game, too, by offering the aggregation of their customers. Again, we don't know, and we didn't know when I was on the commission, what the makeup is. We just know that CPS Energy or Reliant or TXU will curtail their load, and they can do that because they have programs that they incent their customers there to participate by paying them—usually but not always—but most of the programs are structured in a way that ays, "We, the load-serving entity will pay the residential customer, $1 a kilowatt or 50¢ a kilowatt, which will show up on your bill as a rebate." Those programs, at least in the private conversations I had with management at the time, the customers are responding to it, including residential.

The biggest percentage may well be larger customers because, obviously, the savings are greater for larger customers on a relative basis. Nevertheless, customers are signing up across the whole spectrum of customer classes.

Respondent 3: If I can get back to the initial question about platforms. I think it's a really interesting question. In my presentation, I talked about making LMP a default within the context of a broader set of customer choices, which really was alluding to some degree to this. That you make the LMP a default, but you're offering it in the context of also giving the customer access, for example, to financing and access to specific demand-management technologies which you certified as interoperable with your price signals.

They might be smart thermostats, they might be apps, a whole range of things. There also might be different payment options, your hedging options or other kinds of products that might be available.

This really was a concept that builds on something that we talked about in a study that we did for New York REV. When people ultimately see the presentation, there are references and one of the references is to that study that we did for NYSERDA as part of the New York REV process, where we not only looked at distribution-level, locational marginal pricing, but we looked at the development of platform markets, with the idea there, the commission particularly was interested in utilities combining on a platform market which would offer services in addition to energy.

This is something, if you go back to the basics of what do we mean by a platform market, a platform market is the infrastructure of an ecosystem that matches producers, not just the utility. The utility could offer some apps on it, presumably, but it would be offering it in competition with other providers of similar technologies and apps. It matches producers and consumers, which in this case could be individual consumers. It could also be a competitive load-serving entity on the other side.

It then provides the components and rules that are designed to facilitate those interactions and transactions. There could be both a platform sponsor, which might be the utility or a group of utilities, and the platform provider or operator, which actually facilitates the transactions.

Whether utilities will do this or whether this becomes Google or Amazon or someone else taking this role in the utility space, I think is an open question. We've had conversations with utility clients, some of whom have expressed interest in this, and you see early prototypes of things like this with utility marketplaces where they do offer connected home devices. I don't know of any utilities that have really made significant investments and really pushed those marketplaces as a way to connect with their customers.

In particular, I don't know to what degree utilities are actually using the data that they have on their customers' usage patterns to really curate offerings for those customers and connect them to the offerings that would be most valuable for them. But that's an opportunity that I think is available to utilities, particularly where you have a commission that will allow the utility to share in some profit from offering these kinds of adjacent platform services.

Moderator: Great. We're coming up on the end. I'm going to stop with taking questions since we only have about three minutes left. In part, because I want to take full advantage of my privilege of being moderator to make one or two comments at the end. They ideally would lead to a conversation. But maybe that's another session.

Following up on to the innovation question, my sense is that, at least for the residential customers, for many of them there's just not enough money in the game. And so the angle might be one where the innovation takes place by companies for whom there are other benefits. So I think Tesla, for example, is a good example of somebody who is, by themselves, very aggressive in thinking this through.

And, for them, it might be more an additional feature to the cars that they sell that makes the cars themselves more attractive as a hook to getting buy-in from consumers. That's one thought.

Then, I really liked the small comment about offering financing. I think there's also another topic, perhaps, about the fact that we think about demand response. It's naive to think that it's just behavioral in some ways. In many instances, it actually requires CAPEX and no fuel expenses. So the notion that there is some kind of price volatility in the future that allows me to adjust something, and I have to spend $30,000 up front to have the technology in place to do it, that by itself may not be enough.

So that might be something else that's needed in addition, at least for certain types of consumers to actually invest in flexibility of the demand in a way that then has positive impacts.

Anyway, those are just two thoughts. I thought this was a really fantastic panel and a really great conversation amongst all the participants.