BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the matter of: :

PRICE FORMATION IN ENERGY AND :

ANCILLARY SERVICES MARKETS : AD14-14-000

OPERATED BY REGIONAL :

TRANSMISSION ORGANIZATIONS AND :

INDEPENDENT SYSTEM OPERATORS, :

SCARCITY AND SHORTAGE PRICING, :

OFFER MITIGATION, AND :

OTHER PRICE CAPS WORKSHOP :

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Federal Energy Regulatory Commission

Room 2C, 888 First Street, Northeast

Washington, D.C. 20426

Tuesday, October 28, 2014

The technical conference in the above-entitled matter was convened at 8:45 a.m., pursuant to Commission notice, when were present:

FERC COMMISSIONERS:

COMMISSIONER PHILIP MOELLER

COMMISSIONER TONY CLARK

COMMISSIONER NORMAN BAY

FERC STAFF:
MODERATOR BOB HELLRICH-DAWSON, AM Presiding
MODERATOR EMMA NICHOLSON, PM Presiding
MICHAEL P. McLAUGHLIN
ARNIE QUINN
JAMIE SIMLER
WILLIAM SAUER
SETH JENSEN
JOSHUA KIRSTEIN
LAUREL HYDE
MARY WIERZBICKI
SCOTT EVERGAM
CHRISTINA HAYES
DAVID MEAD
ERICA SIEGMOND

PANEL I: GOALS OF SCARCITY AND SHORTAGE PRICING
AND PERFORMANCE OF EXISTING PRICING RULES

Panelists:
MATTHEW WHITE, ISO New England, Inc.
TODD RAMEY, Midcontinent Independent System Operator, Inc.
ROBERT PIKE, New York Independent System Operator, Inc.
ADAM KEECH, PJM interconnection, L.L.C.
RICHARD DILLON, Southwest Power Pool, Inc.

PANEL II: LESSONS LEARNED FROM EXISTING
SCARCITY AND SHORTAGE PRICING RULES

Panelists:

JOSEPH CAVICCHI, Compass Lexecon, speaking on behalf of Electric Power Supply Association

ERICA BOWMAN, America's Natural Gas Alliance

JOHN CITROLO, PSEG Power

CHARLIE BAYLESS, North Carolina Electric Membership Corporation

JOSEPH BOWRING, Monitoring Analytics

PANEL III: GOALS OF OFFER CAPS AND
MARKET POWER MITIGATION

Panelists:

ERIC HILDEBRANDT, California Independent System Operator Corporation

JEFFREY McDONALD, ISO New England, Inc.

SHAUN JOHNSON, New York Independent System Operator, Inc.

JOSEPH BOWRING, Monitoring Analytics

CATHERINE MOONEY, Southwest Power Pool, Inc.

DAVID PATTON, Potomac Economics

PANEL IV: IMPACTS OF OFFER CAPS AND
MARKET POWER MITIGATION

Panelists:

JOSEPH CAVICCHI, Compass Lexecon, speaking on behalf of Electric Power Supply Association

ABRAHAM SILVERMAN, NRG Energy, Inc.

EDWARD TATUM, Old Dominion Electric Cooperative

JEFFREY NELSON, Southern California Edison

CHARLIE BAYLESS, North Carolina Electric Membership Corporation

PATRICK CONNORS, WPPI Energy, speaking on behalf of Transmission Access Policy Study Group

Court Reporter: Jane W. Beach, Ace-Federal Reporters, Inc.

P R O C E E D I N G S

(8:45 a.m.)

MR. HELLRICH-DAWSON: All right. Welcome to today's Workshop on Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators.

This Workshop is part of the Commission's effort to better understand the market design and operational practices that can impact price formation in the energy and ancillary services markets.

We are going to use our time today to identify and discuss the technical, operational, and market issues surrounding two topics: shortage or scarcity pricing here in the a.m., and then offer mitigation and offer caps in the afternoon.

I want to thank all of our participants for being here today. I'm sure we're going to have a very lively discussion and it will be very informative. And I also want to welcome, I think Commissioner Bay has walked into the room. Good morning.

Chairman LaFleur, regretfully, could not be here this morning. She had a family medical issue to attend to. Prior to describing our panels, let me go ahead and turn to Commissioner Bay and see if he has any remarks or anything he would like to say?

No? Nothing? All right.

Let me go ahead and take the opportunity, then, to introduce everybody here at the table, or have them introduce themselves, actually. I'm Bob Hellrich-Dawson. I work in the Office of Energy Policy.

Dave, do you want to go ahead, and go this way?

MR. MEAD: I'm David Mead, also in the Office of Policy.

MS. HAYES: Christina Hayes, OEMR-West.

MR. EVERGAM: Scott Evergam, OEMR-East.

MR. KIRSTEIN: Josh Kirstein, General Counsel's Office.

MS. WIERZBICKI: Mary Wierzbicki, Policy Office.

MS. NICHOLSON: Emma Nicholson, Policy Office.

MR. McLAUGHLIN: Mike McLaughlin, Policy Office.

MR. QUINN: Arnie Quinn, Policy Office.

MS. SIMLER: Jamie Simler, Policy Office.

MR. SAUER: William Sauer, Policy Office.

MR. JENSEN: Seth Jensen, OEMR-East.

MR. HELLRICH-DAWSON: Okay. So as noticed in the agenda, we will spend the first half of the day discussing shortage pricing and the second half discussing offer mitigation and offer prices--or, excuse me, offer caps.

So we have four panels today. Panelists have already submitted background briefing materials in advance, so for all of our panelists we are going to skip the formality of any presentations or opening statements and move straight to discussion, which is sort of how we did with the Uplift Workshop, if you remember that one, if you attended.

All materials received have been posted to the Calendar Pages on ferc.gov, and will also be posted on E-Library under Docket No. AD14-14. Staff will be using the contents of its recently released papers on shortage pricing and offer mitigation to help frame our discussions today.

In our first panel are representatives of Regional Transmission Organizations and Independent System Operators we will discuss how the goals of scarcity and shortage pricing are balanced against the operational realities of employing administrative pricing rules.

This will include a discussion of their current existing rules regarding shortage pricing, their experiences with shortage events and shortage pricing triggers; how operator actions impact price signals; and coordinating across seams during shortages.

In the second panel, market participant representatives, including power suppliers and load serving entities and the market monitors will discuss how shortage pricing impacts participation in the energy and ancillary services markets, and what lessons they believe we have learned regarding efficient pricing.

We will also have the RTO and ISO representatives at the side table to offer their technical expertise.

In the third and fourth panels we will turn to the topic of offer mitigation and offer caps. In the third panel we will hear from the RTO and the ISO market monitors about market power mitigation provisions and how they interact with price formation.

We will also ask the market monitors how energy offer caps interact with shortage pricing rules and market power mitigation rules.

In the fourth panel we will hear from market participants about the impacts of offer mitigation rules and the offer caps. This panel includes representatives from both generation and load serving perspectives. RTO and ISO representatives will again be seated at the side table during the panel to offer their technical expertise.

We will take some short breaks between panels between 10:30 and 10:45. We will take lunch at 12:30-- that's what we have the schedule for, at least right now. From 12:30 to 1:30. We will have another break between the third and fourth panels at about 3:30, and then we will plan to wrap up at 5:00, fingers crossed.

(Laughter.)

MR. HELLRICH-DAWSON: We have a lot of ground to cover. We've got just a little bit of time, one day here. With that in mind, we would like panelists to keep their comments within the topics laid out for each panel. If the discussion begins to stray outside of the scope of the panel or outside of the scope of the question, we may bring the discussion back on topic.

Additionally, the workshop is not for the purpose of discussing specific cases before the Commission. No ex parte discussions. We have provided notice of certain pending dockets in notices issued on September 5th and October 10th to address the potential for the discussion to touch on issues raised in those dockets. Nonetheless, please refrain from discussing the specifics of pending cases, and that will prevent me from having to redirect the conversation.

Just a few housekeeping matters. No food or drink other than bottled water is allowed in the Commission meeting room. Please turn your cellphones off. There are restrooms and water fountains out the door to your left. Hang another left behind the elevators. You can also go to your right, another right behind the elevators there.

For panelists, if you'd like to be recognized go ahead and turn your name tent card up. Be sure to turn your microphone on and speak directly into it. When you're not speaking, please turn your microphone off to minimize background noise.

We are addressing six different markets here with different rules and different names for things, so please be clear about what it is you're talking about. Avoid acronyms, avoid abbreviations, those sorts of things, and I will, as I said to some of you earlier, take the bullet and ask the question to make you explain things further if need be.

I believe Commissioner Clark has joined us now also. Commissioner Clark, do you have any opening statements or anything you'd like to say?

COMMISSIONER CLARK: Sure. Thank you.

Thanks everyone for being here and for the panelists for being here as well. Today's conference continues one of the more challenging endeavors that the Commission has undertaken in some time. And that is to scrutinize and look at the pricing structures within the markets, specifically the energy markets and scarcity pricing.

As presented in staff's white paper that we received, RTOs and ISOs are experiencing very few shortage events, and seldom see shortage pricing. Now while that could largely be associated with healthy reserve margins--and we'll probably hear a bit about that--we want to ensure that shortage pricing occurs when and where necessary in order to provide accurate price signals to supply load.

And this, in turn, will provide more accurate pricing in other markets such as ISO--such as the RTO and ISO capacity markets. And that is one of the nexus that I'd be interested in hearing about today, and I've been thinking a lot about, is this nexus between the energy markets and shortage pricing in capacity markets.

We hear a lot about concerns about how the capacity markets are operating, and to the degree that shortage pricing mechanisms may provide signals for how generation gets invested in a longer term basis, I'd be interested in hearing panelists' thoughts throughout the day about how fixing the shortage pricing mechanisms and getting accurate price signals there might alleviate some of the concerns that we're hearing about regularly on the capacity market side of the equation.

So it's a big topic. This is probably one of the more important ones, I think in my mind, that we'll be doing throughout the course of these technical conferences. Thanks for everyone for being here, and I look forward to a good discussion today.

MR. HELLRICH-DAWSON: Okay. So our first panel here again is going to--we have our representatives from the RTOs and the ISOs, and we'll go ahead and introduce everybody. I hope everybody's okay with a first-name basis.

We have Matt White from ISO New England; Todd Ramey from the Midcontinent ISO; Rob Pike from New York ISO; Adam Keech from PJM; and Richard Dillon from the Southwest Power Pool.

So generally speaking, shortage pricing is the method RTOs and ISOs employ to price energy and operating reserves during scarcity and shortage conditions when the system operator just doesn't have sufficient resources available to meet both energy and operating reserve needs. But it also serves as a price cap to reflect that tradeoff between costs and reliability.

We're just going to go down the panel here and ask everybody to talk sort of about the philosophy behind your shortage pricing programs and the goals you hope to achieve.

In our staff paper, we articulated two different goals, essentially a short-run goal and a long-run goal of shortage pricing, the short-run goal being efficient price signals that can tell existing demand and supply, send them the right price signal either to increase output or make their output available, or for demand to decrease. And the long-run goal of sending efficient price signals for entry and exit.

Are these the right goals? Do you think these are the right goals? If they're not, what are your goals?

Or what should the goals be? That's the first question.

The second question, a follow on to that then, is if you could describe how your rules work to meet your goals, whatever they might be.

And then what events trigger your shortage pricing? A description in general of how the rules work would be very helpful.

For instance, do any actions taken to avoid a reserve deficiency trigger shortage pricing? Does a deficiency of any particular reserve product trigger shortage pricing?

And not everybody needs to go into the same amount of detail, if one person says yes, we co-optimize between energy and ancillary reserves, we don't need everybody to sort of describe how that happens every single time. One good, clear explanation is great.

So, Matt, can you go ahead and start?

MR. WHITE: Sure. Certainly. Just as I was starting to write down my answers.

(Laughter.)

MR. WHITE: So I'll offer a few things, Bob. You laid out a number of different questions. Maybe I'll just try to touch on some of them and leave some of them for the fellow panelists to add on, since I know many of them have similar principles.

I guess I get to be the first person to say: Yes, we co-optimize energy and reserves in real-time in our dispatch system, and shortage pricing occurs when the dispatch and pricing software cannot simultaneously meet the energy requirements and the reserve requirements.

There are many different reserve products in New England. There are both system-level requirements and local-level requirements. If any of those requirements cannot simultaneously be met, we have shortage pricing. However, the level of shortage pricing depends which requirement or combination of requirements cannot be met at the time.

And I thought your paper did a nice job of laying out an introduction to some of the complexity of how all those pieces work.

Staying at a high level, all of that complexity, and really the goals are much as you laid out in the paper, is designed to serve sort of a core purpose of sending a very strong price signal to the markets when the system is entering stressed operating system conditions.

By doing so, we hope to achieve two things. One is to provide compensation to the supply side of the market for performing as needed--meaning, delivering energy or reserves--in the right times, in the right areas when we face heightened reliability risk.

At the same time, it also provides strong incentives--although in practice we see much less effect on the demand side for buyers in the wholesale market to curb their consumption at the time and in the areas where we face heightened reliability risk.

I think the staff paper did a nice job of pointing out that putting that to work involves a lot of technical details which tend not to be terribly controversial, as well as a lot of core principles in the notion that these prices ideally should be set in a way that reflects the value that consumers place on reliability. And I agree with the paper's statement that the interpretation of that in this context is: How much is it worth to avoid an involuntary load curtailment?

That is in some sense the right goal for us to be shooting for with these designs.

You asked about what events trigger it. I'm just going to note briefly here a comment that was made in the staff paper. New England is, as was noted expressly in the paper, I think you used the words "a little unusual among RTOs" in that we do not invoke emergency procedures until after we see scarcity pricing--at least that's normally how it works.

We think that's the right approach because that sends the price signal to the markets and lets both the software systems and market participants respond, or at least have the maximum opportunity to respond, and resolve the deficiency, the shortage, before we have to roll over and invoke emergency actions.

There's a lot more on emergency actions which we can go into, but I think the staff paper laid out the logic of how that works in the New England system fairly well.

In hindsight, at the end of the day, I think the core ideas here is really to make sure that when the system is stressed we send very strong price signals that reward the resources that perform and deliver the services we need and, similarly, they don't reward resources that don't perform, that aren't helping the system at those same times, which is exactly how a well-designed market should work.

MR. HELLRICH-DAWSON: Thanks, Matt. Go ahead, Todd.

MR. RAMEY: Good morning. Price formation at MISO really starts from a good foundational base co-optimizing energy and ancillary services. Co-optimization in MISO is implemented as part of our dispatch calculation every five minutes with a complete re-co-optimization of the required capacity needed to supply energy and meet all of the operating reserve requirements.

Our design currently includes operating reserve demand curves that kick in when the required operating reserve product is insufficient in any five-minute period. This is also true for our day-ahead market, but as a practical matter day-ahead markets are--it's much more rare to have scarcity pricing in day-ahead markets.

I want to describe three operating conditions and talk about the distinctions in price formation between those three.

The first is what I call "normal operating conditions." It covers 99 percent of the intervals of the year.

The second operating condition is what I would call "tight operating conditions." So you're starting to become limited on the access that operators have to additional resources to bring online to meet requirements. For MISO, this is when we would be getting into operator emergency actions in an effort to maintain operating reserves at the required levels.

And the third operating condition are those "scarce conditions" when you do have a deficiency of your required reserves.

During normal conditions, pricing is pretty effective and efficient at MISO. Again, our coal is similar to, as Matt described for New England, is to have market prices that are reflective of the marginal cost of the actions taken to meet all the requirements for a particular interval, whether that's the marginal costs of a fuel resource that's on the margin, or even through the use of our operating reserve demand curves. Those curves are trying to make an attempt to represent the value of constrained or slightly degraded reliability at that particular interval.

Under normal conditions, good pricing most of the time. The challenges that we have in MISO during those types of conditions include ramp shortages. So given the nature of the fleet in the MISO region, lots of coal-fired generation, relatively slower ramping capabilities. From time to time we will run into transient ramp constraints, just interval to interval, that makes it a challenge to meet the full requirement for that interval.

The second challenge during normal operating conditions are block-loaded resources of long-standing price formation challenge for RTOs.

During tight conditions, again this is when we're getting into operator actions through emergency operating procedures to maintain reserves, MISO--this is probably our biggest area for improvement in price formation--MISO doesn't currently have specific pricing rules to support those kinds of actions taken by operators. We are currently developing a solution to that and wrapping up that conceptual design with stakeholders yet this year.

Scarce conditions, the biggest challenge to scarcity pricing for MISO is the inefficiency of interchange schedules that are induced by the relatively higher prices that are established through the use of those operating reserve demand curves. The staff paper covered this issue in a couple of examples.

When MISO is close to being in scarce conditions, it's typical for PJM to be close as well. Really, it's megawatt definitions of when those scarcity prices kick in. The timing differences between the two RTOs can incent pretty significant interchange schedules, so you can get some pretty volatile interval-to-interval pricing, RTO-to-RTO pricing due to the inefficiency of those schedules.

So with that, I will close my initial comments and let Rob have a chance.

MR. HELLRICH-DAWSON: Thank you, Todd. Rob, before you start, let me go ahead and note that Commissioner Moeller has walked in the room here and joined us. Do you have anything you would like to say to start us off?

COMMISSIONER MOELLER: No, thank you.

MR. HELLRICH-DAWSON: All right, thanks. Rob?

MR. PIKE: Thanks, Bob.

I'll try to do a higher level summary here. You asked a ton of questions there to kick us off, so hopefully you'll take us into the more detailed aspects.

Just to kind of clarify the language from the NYISO's perspective, we have what we would call shortage, and we have a product which we call scarcity pricing.

So shortage pricing is the classic operating reserve demand curves that many of the markets have. They are embedded in our dispatch. I'll throw the plug that every five minutes it's a co-optimization looking to make the tradeoffs between energy and ancillary services. And these operating demand curves are used when there is insufficient resources.

In the absence of them, you'll find the dispatch tools which are straight mathematical engines making some very strange output decisions to try to come up with solving these constraints without these demand curves in there.

So the demand curves serve a vital role from the dispatch tools themselves of just helping them find the appropriate solution to run the grid, but to establish what those pricing points should be in the absence of a complete set of resources.

Scarcity pricing in New York is implemented when we activate our emergency demand response programs. The philosophy behind that is, we are paying the demand response a price, $500, to reduce their load draw on the system. We want to make sure the market is being compensated fairly, or consistently with that. So it's a mechanism that we run a but-for test that looks to say did the activation of demand response solve the reliability problem that we were having?

We do that by a measure of available capacity. And if so, it was a beneficial call so let's make sure all of the market is being cleared consistently from a pricing perspective. So just kind of a clarification of what those two products are in New York.

They have been implemented. The demand curves have been implemented since 2005. The scarcity pricing has been implemented since 2003. It continues to be reviewed within our stakeholders. We've made evolutions to both of those products over time, adjusting the setpoints, adjusting the conditions under which they run and are actually active in our stakeholder process right now looking to modify both of those programs.

One of the changes that's underway is looking at the locational needs of operating reserves. New York has two locational reserve products, one on Long Island, one in eastern New York. We are active with our stakeholders now in understanding whether we need a product in the lower Hudson Valley.

And really the idea behind these locational products is they represent transmission constrained areas, and they represent the fact that you can't get power into those regions. So if you lose capacity within those regions, you need to be able to restore the grid within those regions. So this is a directional product intended to make sure the reserves are available where you need them and when you need them.

The other change that's happening to our scarcity pricing rules, as I talked about this but-for test, this test that says was the activation of the program an appropriate call and therefore should the prices be set consistent for all resources? Within our stakeholder process, we are looking to say how do we move that construct into the actual optimization engine itself? Move it in as a requirement that's dispatched to, and then simultaneously clearing all of the products.

The value of doing this, today it's done after the fact. Today we run just an engine after the dispatch to calculate what the prices should be. By being able to do it within the dispatch tools, now you're getting some consistency for all resources between the energy and the ancillary prices.

But one of the big pieces that's missing in today's implementation is a price signal to the proxy bus locations to the transaction nodes. And by putting it within the optimization, we can make sure we're signalling imports and exports across the region, as well, to try to deal with shortage conditions.

You know one of the questions that was raised is, you know, should you be committing resources to avoid shortage conditions? And to me the answer is: If they're available, absolutely. You know, so that's the value of putting it in the optimization products themselves, is we can make the forward commitment decisions either from internal resources, or we can make them as part of the import-export decisions.

We will import energy if it's cost effective. It's an economic evaluation within the tools. Next week New York and PJM will activate our coordinated transaction scheduling protocol, which is looking at the price difference between the regions. We'll take PJM price information into the New York dispatch tools and we'll pair that with a CTS bid, a bid that's a difference in price between the regions and schedule those transactions based on the economics of the two regions.

One of the main drivers of that was the volatility that Todd was referring to between the regions and interchange schedules. We're expecting that to greatly help that process in moving power to the right region and the right conditions.

I guess the original operating reserve demand curves were set at approximately a $500 range, some of the reliability rules. That was really representative of the upper range of the dispatch resources that were available.

You don't want to forego resources that are available. You don't want to not schedule reserve if the product is available, but you don't want to set, you know, an infinite price, either. There's a practical setpoint. So it was a tradeoff in that conversation to reach an upper end.

Within the stakeholders now we are discussing moving that $500 to a $750 price. And really that's reflective of some of the higher cost resources that we're seeing in the market now, particularly under tight conditions, particularly under high gas cost conditions that the prices are getting up into the $700 to $800 range. And so that's probably a more appropriate range for our demand curves to be set at.

One of the important pieces, certainly the demand curves and the operating reserve shortage pricing is an incentive. It's a performance incentive for resources. If you get a day-ahead schedule from generating resources, there are consequences, significant consequences for not being available into real time.

So it's important for us to see that opportunity come across. I think to Commissioner Clark's point, though, it's a significant source of potential revenue for a resource. This is a product that is calculated as a net energy and ancillary service revenue, and ultimately is used within the capacity market as a source of revenue.

So the capacity market is the missing money. It's the difference between what could have been earned in the energy market and what's remaining. And so we do see the shortage values are a significant contributor to net energy and ancillary service revenues.

They're not all of it. It's not going to replace the capacity market, but it certainly is a balance between how much money needs to be recovered in a capacity market and how much should be covered in an energy market.

I don't want to go into a lot more detail, Bob. We'll go through the panel and go in deeper questions.

MR. HELLRICH-DAWSON: Could you just clarify one thing? You talked about an ongoing stakeholder process regarding the, when EDR--or, sorry, emergency demand response triggers the pricing.

MR. PIKE: Yes.

MR. HELLRICH-DAWSON: So if you were to make this change, what would the effect be?

MR. PIKE: So there are two stakeholder processes. One is looking at the operating reserve demand curves, and that one is looking at saying the demand curve--of the products we have today, there's essentially nine products: three reserve products, spinning reserve, 10-minute reserve, and 30-minute reserve; and three locations, Long Island, East New York, and all of New York. Four of those requirements are driven by explicit reliability rules. And so those have the higher operating demand curves setpoints.

The remainder are best practices, which is really saying it would be best to distribute your reserve across the system, if you could do so. They're set at a $25 range, really just reflecting. We'd like it distributed, but there's just a reasonable cost to have it distributed.

The four reliability driven operating rules would change the value from a $500 per megawatt hour for the ancillary service product, to $750 or $775 depending on the product. And really that reflects the upper end of the resource costs that we see under tight conditions, and reflects that we would want to commit those resources to solve the reliability need.

MR. HELLRICH-DAWSON: But you mentioned something about your emergency demand response and when you call on those.

MR. PIKE: So that's the scarcity pricing program. And what that's looking at doing is saying--today it happens, we run our dispatch tools. And before the prices get to the website, we run a price calculation tool on it that runs this but-for test.

What we're trying to do is move that calculation actually into the co-optimization engine as an operating reserve requirement. Essentially the test is saying do I have enough operating reserve on the system that it reflects the activation of the demand response was worthwhile, meaning if I hadn't activated the demand response I would have been into a shortage condition.

By moving that into the optimization itself as an additional operating requirement, operating reserve requirement, you make the tradeoffs on transmission utilization and energy and operating reserve, as well as imports and exports. It's all embedded into the tools. So they're making the purest economic decision of how to operate the resources, given that you have this extra reserve requirement, or availability requirement on the resources.

That's an ongoing stakeholder process. We're looking to do that in the summer of '16 as an implementation.

MR. HELLRICH-DAWSON: Thank you. Adam?

MR. KEECH: The first question you asked was, do you or don't you agree with the goal of a shortage pricing model, as you stated in the paper, where the short run was appropriate price signals and valuation of resources in real-time, and in the long run was entry and exit information from the market.

I think from our perspective we agree with both of those as goals. The one thing I would say is that in PJM where we have a fairly robust capacity market, a majority of the information that people are using to make investment decisions going forward are coming out of that capacity market.

It's a much more stable signal, whereas some of the things we've discussed this morning is sort of the unpredictability in shortage hours and prices associated with that. And it's tough to make a long-term informed decision based on something that is very unpredictable.

So in PJM a majority of the information being used for investment is coming out of the capacity market, although certainly a goal of a shortage pricing model is to give some information to long-term decisions.

In PJM, we have what we call "shortage pricing." And really what it is is a lot of what's been talked about from the other panelists. It's a joint optimization of energy and reserves in real-time. And the reserves we use for our shortage pricing methodology are 10-minute primary reserves, and 10-minute synchronized reserves.

And we look at those requirements and whether or not we can meet those requirements in real-time as sort of the first trigger for us to have shortage pricing.

We have operating reserve demand curves for all of those products. Currently they are set at $550 per megawatt hour, and they will go up to $850 per megawatt hour starting June 1st of this coming year.

We have an RTO-based market for which we price shortage for nonsynchronized and synchronized reserves, and we also have subregion, which is the Midatlantic and Dominion area of PJM for which we have sort of local requirements.

That area is typically transfer-constrained going from West to East, and so when we have the inability to deliver reserves, or when the loading of reserves would violate the transfer interface, which is the import limit into that region, we will split reserve prices and potentially have locational shortages instead of systemwide shortages.

So the first trigger I mentioned for the reserve shortages and the invocation of shortage pricing in PJM is the inability to meet those reserve products in any location at any time.

The second two sets of triggers, which are sort of a belt-and-suspenders' kind of method, is the commencement of a voltage reduction in PJM in any area where we have a reserve requirement, or a manual load dump.

And the reason we have those as sort of forced triggers of shortage is if for some reason we have bad data from generation resources such that our reserve requirements and our reserve quantities would indicate that we have enough reserves yet we are initiating fairly severe emergency procedures, we would force the prices to be indicative of a shortage.

And really the only reason we have that is if for some reason we have some kind of measurement error on reserve capability in real-time where our operators do not believe that they have as much as the data would indicate.

We've seen instances of that in the past, and so we wanted to make sure that we caught that when we implemented the shortage pricing methodology that we have today.

One of the things that makes PJM unique from some of the other areas, while we do a five-minute co-optimization of energy and reserves, we have sort of a dead band around when we would implement shortage pricing so that we intentionally avoid transient type of shortages.

And when I say "transient," I mean inability to meet the reserve requirement on maybe a five-minute basis or something like that.

We have protocols in place where we have our five-minute economic dispatch algorithm which is doing the minute-by-minute joint optimization, but we also have a longer term look-ahead algorithm that is really responsible for unit commitment.

So our dispatch procedures incorporate sort of this longer term, which we call intermediate term application, which is largely responsible for unit commitment. And then we have a short-term application which just dispatches the units online.

And what we want to ensure is that before we actually indicate that we have a shortage of reserves, it's somewhat persistent and it's not a result of we have a unit coming online in five minutes and it's just not online now, and so we're going to spike the clearing prices.

From our perspective, that was sort of a--our perspective on our members' perspective, that could be more damaging than helpful. And so we put specific provisions in place to avoid those types of transient types of issues.

We allow a lot of the emergency actions that are taken by operators to set price. So if for whatever reason we solicit for emergency purchases and we accept some of those, those transactions can set price just like any other generator or demand reduction.

Emergency demand response in PJM can set price. Emergency segments on generators can set price. And these were all things that were part of the most recent incarnation of our shortage pricing procedures, but they weren't prior. And that most recent set of rules went in place October 1st of 2012.

To Todd's point earlier, one of the biggest areas for improvement and something that we've been focusing on in our stakeholder group, and what tends to result in us having counterintuitively low prices during peak conditions, is interchange volatility.

We tend to see that when we have high prices, or there's an expectation of high prices. We tend to get a lot more interchange than what PJM would have estimated, and so we've scheduled based on some expectation of interchange, and then we get a fair amount more than that. And that has a very substantial price suppressive effect.

We have a stakeholder group that's been working for awhile called the Energy and Reserve Pricing and Interchange Volatility Subgroup, which was tasked with tackling that interchange volatility issue, and also tasked with making sure that as much of the operator actions around things like conservative scheduling, that we incorporate that into the market clearing engines and the reserve and energy price calculations as possible so that we don't get price suppression during conservative scheduling periods, and that we eliminate the potential, to the extent possible, for large interchange swings at the peak that could be counterproductive from a pricing perspective.

That group has been working for probably the larger portion of this year, and it's got some good stuff coming up that will be voted and hopefully approved at one of our higher level members' committee meetings on Thursday.

And with that, I'll conclude my comments.

MR. HELLRICH-DAWSON: All right, thanks, Adam.

Richard, you can go ahead.

MR. DILLON: Good morning. As tempted as I am to say "me too," there's always some additional items to add.

One of the additional items is the environment within which SPP operates. It has no retail open access whatsoever. So all of the load serving is under some sort of jurisdictional, local jurisdictional, whether it be through a muni, or something like that. And that causes some differences.

That means that another difference is that there is not a capacity market in the Southwest Power Pool. So as much as I would like to just gloss over the entry pricing, even with that some of the items that have been mentioned earlier in the--by other presenters is also true at SPP.

At SPP there are reserve areas. And to the extent that it is difficult to move energy in or out of those areas, they can trigger shortage pricing. And that shortage pricing could act as an entry signal.

Now because it is transient and in fact right now one of the things of doing things well, like expanding the transmission, is you start relieving those issues through a transmission solution. And that is what's happening at Southwest Power Pool.

And so even though the reserve zones exist, at this point we're not having to constrain to those. But the possibility is there.

The capacity situation within Southwest Power Pool is that we have in excess of 25 percent reserves off of time-of-peak. So it's in excess of 63 gigawatts of generation with roughly a 47 gigawatt peak currently prior to other parties' adding.

And so again the entry pricing purpose, which is a very valid point of scarcity pricing is not really in play to any significant portion at Southwest Power Pool.

Now the price signals is definitely in play. We are one of the ISOs that has subhourly real-time pricing. And so the transient pricing that occurs we are hoping will start incenting some changes, but we have an industry inertia that we're dealing with.

And the industry inertia that we're dealing with is the same one that's been mentioned by other parties, and that is the interchange scheduling. The industry inertia is everybody plays hot potato at the top of the hour, and using

Central Time at seven o'clock in the morning and eleven p.m. in the evening there is a massive turnover that's going on as we move from on-peak to off-peak and vice versa.

And as a result, there is no new electrons that are being produced; it's just which region has to produce them, which causes ramping issues.

The five-minute settlement that is being used in real-time at Southwest Power Pool was put in place for a couple of reasons. One is the co-optimization of the reserves. It's real hard to turn around and integrate a capacity number.

Energy can be integrated. In other words, averaged out to an hour. But capacity numbers, as you move it around and you say now you're going to provide 5 megawatts of capacity for regulation, and the next 5 minutes you may not, that becomes very difficult.

So to keep the pricing fairly aligned with the actual operational decisions, we decided to go to 5-minute. But the other issue, which is ramping, was another reason that we went to 5-minute. And the hope is that over time parties will start seeing that trying to put in a schedule that ramps at 5 minutes before to 5 minutes after the hour, everybody playing hot potato right there causes price spikes, and maybe I can make a little bit more money if I move it to starting at 5 minutes after the hour. And yet the energy that's produced is still the same across the hour.

In other words, it is an attempt to try to overcome some of the industry inertia of decades of practices. Because ramping is, as Todd mentioned and others have mentioned, ramping is a way that we're getting scarcity pricing.

Even though explicitly ramping cannot create the scarcity pricing, what happens is you start robbing the reserves because energy is the most important item that's out there. And so when you deploy it for energy, if there is insufficient capacity on for all the other products, then you rob it out of those products which triggers scarcity pricing.

So although ramping is not directly triggering it, it does contribute towards a trigger as you run short of the capacity for reserves.

The--you know, I've mentioned the 5-minute pricing. So mostly scarcity for us is based on the price signals. The other thing that is not quite consistent across the markets but it's the way that Southwest Power Pool implemented, we basically set the scarcity pricing demand curves based upon the safety net offer caps for each of the products.

So that means that one of the demand curves is set at $1100, $100 above the $1000 safety net offer cap. And so ours were coordinated with the offer caps that are out there right now. And as we coordinate across the industry, if there's discussion about moving the offer caps then we would have to also look at moving the scarcity pricing.

The rationale is that if the offer cap itself does not result in sufficient capacity being online to provide what is necessary, then we have to have a mechanism that allows parties to recover more than what is offer capped. And that was the basic rationale behind the setting of scarcity price values in Southwest Power Pool.

And so they are somewhat linked, which means coordination of safety net offer caps to help prevent what has been expressed about PJM and MISO about parties slapping in interchange schedules to try to capture part of that pricing.

That's something that we have to be aware of at Southwest Power Pool since our neighbor is MISO. And to the extent that there is a pricing differential through the offer caps or through other items, we have to be sure that we're cognizant of that.

We also have to be aware of the potential impact of MISO using hourly real-time prices versus our 5-minute prices. The nice thing about the 5-minute prices is it is so transient, especially in regards to scarcity pricing, that by the time the parties see it going on you cannot slap an interchange schedule in there and try to pick up part of the pie because it's gone.

And so everything always has a consequence. Some good consequences, some negative consequences. The 5-minute pricing has been helpful for us not having reactionary interchange schedules, but again I am in hope that we will see changes in operations specifically on interchange schedules over time as parties realize that they could actually make more profit by moving off of time-of-peak, or ramping peak, I'm sorry, yeah, the 5-minute before to 5-minute after the hour.

So we are essentially the same as everyone else in the gross application, but there are some finer details that were put into the design to try to take advantage of items such as scarcity pricing.

Thank you.

MR. HELLRICH-DAWSON: Thanks, Richard. Actually I want to follow up on this idea of the transitory nature of the ramping causing shortage events.

But first I want to see if anybody else here, my colleagues, have any questions?

(No response.)

MR. HELLRICH-DAWSON: Okay, sorry, Richard, you were just talking a lot about ramping constraints leading to shortage pricing, or not.

Todd, you mentioned that you do sort of a--sorry, no, it was Rob, or one of you mentioned--

(Laughter.)

MR. HELLRICH-DAWSON: --that you do a look ahead that specifically avoids those short, one or two interval--it was you, wasn't it, Adam--one or two interval shortages.

In MISO, you guys are in the process of implementing extended LMP that should, I believe, one of the intents of it was to avoid having those one or two interval shortage pricing events, which you seem to have a lot of, at least from what we could tell.

And then at SPP we've got rules that explicitly disallow a direct shortage pricing event to occur because of ramping, but there are nonetheless indirect ones as you were explaining.

Could each of you just sort of address this issue, sort of how it works in your RTO? But then also the philosophy of if you're short, you're short; why not have a shortage event, especially if it's not going to impact interchange scheduling like you were describing, Richard, and end up with inefficient flows? Or perhaps the alternative view that, well, it's just transitory; we shouldn't be invoking shortage pricing?

MR. RAMEY: I'll go ahead and take a shot at the question. At MISO we really are trying to focus, even at a five-minute level, of having pricing at all locations that is reflective of the marginal resource being consumed.

So the challenge is with the implementation of operating reserve demand curves is essentially you're required to decide on an administrative pricing structure under those conditions, but the rule should be: Is the pricing in every five minutes reflective of system conditions at that time?

So what we have learned at MISO through the implementation of our initial operating reserve demand curve in 2009 was that there are pricing outcomes, or there were pricing outcomes driven by those initial operating reserve demand curves that were producing prices, often driven by transient ramp shortages, pricing outcomes when you did an analysis after the fact, did those prices accurately represent that marginal resource being consumed?

Often the answer was, no. So this value that I'm talking about is very situational. One five minute the value of a megawatt shortage of spin from a system operator's perspective could be quite different from another five-minute interval where he's short a single megawatt of spinning reserve.

So through analysis and looking back and asking ourselves the question: Did the pricing outcomes reflect accurate system conditions? You're again forced to do some averaging, but our conclusion was that oftentimes for example some of those prices early on, one megawatt of regulation shortage produced an $1100 scarcity pricing signal for one five-minute interval.

So, you know, operators asking questions. We've got stakeholders asking questions. What do you want us to do, MISO, in five minutes to react to a $1100 pricing signal? Do you want us to commit a unit?

Well, no, we don't want you to do that. We go with the system operators. Did you see this coming? Yes, we could see it coming but I knew it was transient. I knew it was a five-minute event. My choice was to go short of an operating reserve at a small increment or to commit a resource and commit the market to bearing the cost of that commitment decision to solve a five-minute problem.

So working back and forth between operators, how they view system conditions and the value of reliability either from an operating reserve perspective, or even a transmission constraint perspective, what is it that's causing them to make decisions on unit commitment? So unit commitment even in real-time time frame is how you solve scarcity events.

So you've seen since 2009 MISO has made several filings to adjust the design of those curves. And you can see our philosophy has evolved to small shortages of operating reserves typically translates to a small perceived impact in terms of system reliability. And so you've seen that $1100 2009 shortage price has come down to less than $100.

So now in MISO, most of those scarce, transient events are really very small shortages against their total requirement produces a much smaller pricing impact, but we still think it's important. A shortage is a shortage. We should try and make some estimation of what the marginal value of that shortage is and include that in pricing.

MR. MEAD: Could I just ask a follow-up question? And that is, I wonder if scarcity or shortage pricing were triggered by the short-term events, could that encourage resources to develop more ramping capability?

MR. RAMEY: Sure. So the marginal value of the resource being consumed has a value, somewhere between zero and possibly some very high number.

So again the challenge is to evaluate actual system conditions, make some reasoned estimation of what that value is for most conditions under similar operating circumstances, and design your operating reserve demand curves to be reflective of that.

You know, MISO is a stakeholder-driven process, so there's data analysis discussion. We have an Independent Market Monitor who is very interested in efficient price formation and helps us do those discussions, as well.

So we don't think zero is the right answer in most circumstances, but is it $1100, or even $2500 for a five-minute shortage, a very brief period of time for very small shortages an operator can see coming but he chooses not to commit his way out of it because he can see the relief coming through just the dynamics of the system in a very short amount of time.

Is that helpful?

MR. MEAD: Are you saying that when there are these transient shortages you might see some value in some scarcity pricing but not the full monte that is built into your current system?

MR. RAMEY: Scarcity pricing is a generic term to refer to administered price curves to set prices. Then the scarcity pricing during those events of short durations in time, in small shortages relative to your requirement, are deemed to have very low marginal value impacts to system reliability. So we have adjusted our curves to be reflective of that lower value.

MR. PIKE: So I thin there's two sides to that question, and I do believe it's a balancing act. So I think one of the questions is, or one of the sides is: Did you get a transient price spike because you were artificially constraining the available resource set?

And really what I'm saying is: Did you get surprised? Could you have not been surprised? One of the drivers of putting in our forward-looking dispatch tools, our dispatch tools are looking out 60 minutes in a time-link dispatch, so they see upcoming system events.

They see generators starting. They see transactions changing. They see outage conditions changing. And they're ramping to be prepared for those.

Now that doesn't mean that there's not a big ramp at the time the event is coming, but that's the lowest cost decision we're making in those tradeoffs. But we're preparing so that we're not surprised, and so that's a good counter-balance to it.

These price spikes, these transient price spikes were a big driver in our move to quarter-hour transaction scheduling to get off of the top-of-the-hour huge ramps that we were seeing.

And we've seen, as we've moved to quarter-hour scheduling with our Hydro Quebec and our PJM border a significant dampening of those transient price spikes at the top of the hour.

And I think, you know, to the extent that you've got rules and barriers within your market design that don't let flexibility into the market, I think that's a focus point to try to improve the tools and improve the operation of the market.

On the other side of it, they reflect in our opinion a shortage condition. You don't have enough of a product, and you're making tradeoffs and going short. We have a number of $25 and $80 operating reserve demand curves also in our regulation market. We have an $80, as a lower end demand curve. So we acknowledge that we're willing to make those tradeoffs.

We're willing to go short of regulation service to meet an energy requirement, and we make that tradeoff, and we accept that price signal into the market.

I do think it's an important signal for resources to be flexible. It's there if you are dispatchable and online and available, and you can capture that. If you don't send the price signal, I think it continues to deteriorate because there isn't an explicit benefit of being on the system to capture those benefits.

So I think there's a tradeoff. I think you don't want artificial barriers. Are market designs causing you to see a lack of resource flexibility? But when you're in that case and you're making the tradeoffs, it's an effective price signal at signalling a service you need.

MR. HELLRICH-DAWSON: Matt?

MR. WHITE: Thank you, Bob. I would agree with and second many of the comments of my colleague, Rob, on the five minutes. We price--we can have scarcity prices that are as short as five minutes. On particularly memorable days they can last as long as four hours.

(Laughter.)

MR. WHITE: Those last in our memories for many years. But focusing on the five-minute side, what this really does is it rewards resources that perform on the go when you don't see something happening in advance, and you desperately need them to do exactly what you said right then.

We have some of our most stressed operating conditions happen very quickly. We have a relatively small system, as the ISO footprints go. We have some very large contingencies. We've had days when we lose 1900 megawatts instantly.

We push up 100 units. We need them all to do exactly what they're told. But although we're converting so much reserves to energy that we've almost depleted our reserves, if they all do as asked we'll be out of this in 15 minutes flat.

For those 15 minutes, though, we need that price signal. It rewards the resources that went to exactly what we did. It doesn't reward the resources that didn't go where they should. And over the long term, of course, resources that consistently respond to those dispatch signals during post-contingency conditions when we have to push the system hard to control the disturbance, get the benefits of time after time after time getting scarcity revenue for 5-minute, 10-minute, 15-minute periods.

If you get 120 of those 5-minute intervals over the course of the year, that's 10 hours of scarcity pricing at $1000 scarcity price, that's $10,000 a megawatt year. That is not small revenue. That's like 10 percent of our net cost of entry.

So this does add up to a significant additional piece of revenue, rewarding the resources that are flexible and responsive and do exactly what we need them to do in tight conditions which can, as you know, happen abruptly and maybe only last 5, 10, 15, 20 minutes if everyone does exactly as dispatched.

MR. HELLRICH-DAWSON: Thanks, Matt. Adam?

MR. KEECH: The rules I was talking about earlier in PJM, I'll give you a little bit more detail on them and where they came from.

So we use this two-staged unit commitment and dispatch algorithm in real time where we have one application that does a long-term--when I say "long-term," one to two hours out--economic dispatch along with unit commitment of the system.

And then we have the more short-term myopic dispatch algorithm that is really only moving the units around that's on the system.

The latter application, the short-term one, is the one that's primarily responsible for the calculation of market clearing prices. The operation we have today, and one of the intentions of why we have it today, is we have it set up such that we don't use the demand curve for shortage pricing unless we can't resolve the potential reserve shortage within some amount of time. And I forget the exact amount of time; it might be a half-hour.

And the rationale for that was, when we went through our stakeholder process--and some of the comments that Todd made are sort of in line with what I'm going to say here--is we don't want to have large price excursions because a 30-minute start CT took an extra 5 minutes to come online.

It would send out a price signal that the system is in some excruciated state when in reality a unit just took a couple more minutes to come online than it was expected.

And so there was a concern that the market would be giving information that the system was in a very excruciated state when the operators in the control room didn't have that same perception of the system conditions at the time.

And so that was one of the main concerns in why we developed our shortage pricing system the way we have it today, which is sort of this permission-based system that says if it's not going to last more than maybe a half-hour, it's not relevant pricing information.

Now obviously heard both sides of that argument today, and there are good and bad, and probably the right answer is some balance in between. But that's what PJM--that's where PJM is today with regard to sort of our pricing rules that we have.

MR. HELLRICH-DAWSON: Thanks, Adam. Richard?

MR. DILLON: So I think what you're seeing in a lot of the discussion is a difference in pricing, also. And the pricing I'm talking about is that, you know, we're settling on a five-minute basis. I believe New York now is also. And therefore, the price exclusions, which in our case were specifically set up to incent behavior, not disincent but incent behavior for in our case both ramping--you get paid if you can get there--and also the impact on the interchange schedules is appropriate to let it trigger when it occurs. Because it is in that period.

If you're using an hourly pricing, then it gets averaged out. Now we're talking about these items, and pardon me but the impact that came to mind is this is a lot like a pimple on someone's face. As Bob mentioned earlier, there's not a huge amount of this going on in the industry, but when it does happen it gets your attention.

And what we're talking about is those items that are happening and the attention that it's getting, as opposed to the entire item.

And so you're seeing design decisions that in each case are probably quite appropriate because if you have a one five-minute excursion in an hourly settlement, it's only worth 1/12th of the hourly price. And so the incentive is really marginalized in that case.

If you're talking about a five-minute settlement, now you have an incentive to perform. Unlike New York and their ability to move the interchange scheduling off the top of the hour, right now we're fighting against--you can move at any one-minute in our design, but that's not consistent across the entire industry. And that's back to the industry inertia that the accepted practice is top-of-the-hour.

And that's the reason I'm watching to see if there's sufficient financial incentive to claim more profit by the parties who are scheduling in and out of SPP, shifting their ramping time.

We also allow nonstandard ramp. It does not have to be a 10-minute ramp. They can put--it's called a profile, but they can put in that they'll take 15 minutes to ramp in and out. But right now, we are in the stage of the shortage pricing along with other pricing to provide an incentive for parties to start taking a look at whether they need to change their practice specifically on interchange scheduling in order to alleviate really a system-wide issue of again there's no new energy, it's just who's providing it that happens at the top of the hour.

MS. WIERZBICKI: Richard, I have a follow-up on that. When you talk about the industry inertia to get away from scheduling on the hour, are you referring to market participants within SPP who keep scheduling on the hour? Or also market participants outside of SPP who might be importing or exporting?

MR. DILLON: It's the entire industry. It doesn't matter if it's Eastern Interconnect, Western Interconnect, it does not matter. Definitions of things like what's on-peak and what's off-peak add to that; that on-peak is in Central Standard--Central Prevailing Time 0700 to 2300; and on-peak energy is generally more valuable than off-peak energy.

And so when you have--this probably goes back 30, 40 years of this is when you make changes because we can only accommodate the changes in the days before all the computerization at the top of the hour, that whole inertia is still going forward as an accepted practice when it's now very visible to all of us the cost that's being incurred as I am ramping, assuming I'm supplying to say PJM, I am ramping everything up at 0700. MISO, if that was the only schedule tag across, MISO would be neutral except for the losses. And PJM is ramping everything down at 0700 in order to keep the balance across the Eastern Interconnect.

And so it's an industry practice. It's not an individual RTO. It's not an individual participant. It is a practice. It's not a rule. It's a practice.

MR. HELLRICH-DAWSON: Thanks, everybody. Those were really, really informative.

Following up on something else Richard has brought up a couple of times now. He keeps mentioning the five-minute settlement.

Could each of you just really quickly tell us when you settle? Is it 5 minutes, 15 minutes, an hour? And what you think the pros and cons of the various timeframes are?

MR. WHITE: I suppose we'll just go down the line. We presently settle hourly. We think there's a lot of value in subhourly settlements. We have an ongoing stakeholder proceeding to move to subhourly settlements systemwide with a targeted implementation that I think will probably be in the 2016, cross-our-fingers, time frame to do so.

In a lot of our analyses we find that doing so does a better job of having the price signals appropriately compensate resources for what they actually do during the hour, and it particularly matters for fast-start and flexible resources that are asked to move a lot during the hour.

So we think that's a productive development for our markets, and we're moving forward through the usual process to implement it.

MR. RAMEY: MISO is currently on hourly real-time settlement. So aggregated prices for energy and ancillaries on an hourly basis.

We agree with the past perspective. We think shorter duration is preferred. I would say that's also true for the day-ahead market. So a similar issue that Richard was discussing about scheduling at the top of the hour, hourly day-ahead markets produce unit commitments where commitments are supposed to take place at the top of the hour so you can get some kind of those kind of timing dynamics just even internal to your system.

We are working on, at least in real time--the problem with day-ahead is it's a solution time problem. It's challenging enough to get those day-ahead cases solved on an hourly basis in the four-hour time window.

But notwithstanding challenges from our Independent Market Monitor, he suggests we look at 15-minute day-ahead markets, that'll be a big challenge, but in real time we're currently working on moving to 15-minute settlements for interchange transactions. That's scheduled to go in place next year, the second quarter of next year. And we're just beginning conversations with stakeholders about the possibility of moving to a full 5-minute settlements for our real-time markets.

MR. PIKE: New York is a 5-minute settlement market, has been for the life of the NYISO. And I would agree with the comments.

I think we intuitively say it's really important to have prices and schedules consistent so that resources are fully incented to follow the dispatch signal. They don't ever have to second-guess should I follow the price or should I follow the dispatch? They are the same direction.

You know, the third piece of that is the settlement piece. And then they need to be settled consistent with those prices and schedules so that their incentives are perfectly in line with what our needs are.

MR. KEECH: PJM currently settles on the hour for everything. Shorter settlement periods, specifically 5 minutes, is a topic that comes up probably every couple of years in PJM, especially when we start talking about shortage pricing and interchange schedules and things like that.

But it's never quite got the traction with the membership to sort of get it over the finish line. And so we are on an hourly basis today. We continue to discuss the prospect of going shorter than that, but it continues to be an open item.

MR. DILLON: And Southwest Power Pool is on a five-minute basis from the inception of the marketplace on March 1 of 2014.

MR. HELLRICH-DAWSON: All right, thanks. Dave, did you have a question?

MR. MEAD: Yes. If I understood the discussion so far, on the issue of whether scarcity pricing is triggered in the day-ahead market, I think I heard MISO say yes, and PJM said no.

Could each of you talk about whether your rules permit scarcity pricing in the day-ahead market? And if not, why not?

MR. KEECH: So in PJM today, we don't have a formal scarcity or shortage pricing mechanism in day-ahead. When we designed what we have today for real-time with the synchronized and primary reserve markets, as part of that discussion the theory was that there was so much price-sensitive load in the day-ahead market in PJM that members just wouldn't be willing to buy if the price got to shortage levels. So putting it in the day-ahead market would have been sort of we would put it in there and then it would of just got old and dusty because it wouldn't have ever gotten used.

And so what we have in place today for real-time was a result of the compliance obligation for 719. So it was a little bit of an expedited process, and we haven't gone back and reviewed that decision to not put it in day-ahead. But that's why we are where we are today.

MR. RAMEY: Yeah, at MISO the scarcity price design is fully embedded within the day-ahead market construct. But in the Midwest Region, and even in the MISO South Region, recent historic reserve margins have been in that 25 to 30 percent range for the last decade or so. So as a practical matter you give a day-ahead market with optimization choices on unit commitment and dispatch, you give it a 30 percent reserve margin, as a practical matter the day-ahead market will solve a scarcity problem.

So old and dusty, I would say that would describe the actual practical implementation of our day-ahead market, but it's in there.

Looking forward, however, when 30 percent reserve margins become 15 or less just within the next couple of years, these questions of the effectiveness and the utility of scarcity pricing mechanisms beyond transient ramp shortages could be very much more interesting going forward.

And you could see shortages in the day-ahead market. If the day-ahead market runs out of capacity to commit and it's faced with going to deficient reserves, you will see those price impacts in the day-ahead market at MISO.

MR. PIKE: For New York, the algorithms are identical between day-ahead and real-time, so the operating reserve demand curves are fully implemented into the day-ahead market.

There is a tremendous amount of flexibility in the day-ahead market. So they certainly don't get deployed as frequently as they do in real-time, but they are certainly available to the dispatch tools if necessary.

One of the things we do see is we have a number of $25 operating reserve demand curves and these are--the best practices would like to have reserve distributed, if we can.

Those will be utilized in the day-ahead market. They will reflect at times that that product isn't even available in the day-ahead market, and they'll factor into the pricing outcomes.

MR. WHITE: We don't presently have scarcity pricing in our day-ahead market clearing process for reserves, specifically. I think it's an open question, and this is just commenting on some of the earlier points made, whether if we did it would make much of a difference. Because in general, and I think historically, there's enough flexibility in the system in terms of what you commit when you have essentially all resources, except maybe some nuclear units which are already running anyway, available to you in the day-ahead market and will be able to solve it without being short reserves on a day-ahead basis.

But that's a conjecture. We don't presently have that functionality.

MR. DILLON: And of course our implementation was March 1 of 2014, so it's been a very short period for us. But it's been an interesting ride.

I mentioned earlier how much capacity margin we have. You add to that the virtuals, and what we're seeing in the day-ahead market is that, including a real-time headroom of 1500 megawatts, we're basically committing in excess of the real load in the day-ahead market. So there isn't even an opportunity to trigger scarcity pricing in the day-ahead market.

MR. HELLRICH-DAWSON: All right. Thank you.

Can we move on to actual shortage events and what your experiences have been. Could each of you speak a little bit about how often you actually do invoke shortage pricing, and why?

Is it due to physical shortages? You literally have no resources available, versus an economic shortage choosing to simply not commit the units because they're too expensive?

And given that, do you think you're meeting those goals that we discussed earlier?

And let's just go with that. Matt, could you start us off? Sorry to throw you under the bus, real quick.

MR. WHITE: Sure. My first thoughts were comments that I think I've already said, so I'll go briefly on it.

Since 2012, we've experienced just under 13 hours in total of scarcity hours a year. I pick 2012 because, as the staff report noted, we changed our scarcity prices and raised them on June 1st of that year. Some of those events are five minutes long, but the bulk of it accounts for very large events either during the summer or during winter periods, an hour or more at a time.

When we last revised our scarcity prices in--I shouldn't say "last," when we revised them in 2012, we did so using a methodology that Rob Pike alluded to in New York earlier, which is we looked at and ran an intensive set of offline simulations to set the scarcity prices at a level so that we don't have what we would call artificial economic shortages of reserves. Set the scarcity prices high enough that the software, this wonderful software that can co-optimize everything, can physically make use of every last bit of physical capability in our system to meet the reserve requirements, not quit prematurely because there's effectively an artificial price cap causing a shortage when in fact there's actually reserve potential there.

We figure out what that number needs to be so it's high enough you can use the full capability of the system and we set our scarcity prices at at least that level.

Because of doing so, since that time what we've seen is we see scarcity prices that reflect physical shortage. At the time, you could not meet the requirements given the system and the ramping constraints.

We did see, as the staff report noted, prior to these changes economic shortage of reserves. We had many more events of scarcity pricing prior to 2012 when we had lower scarcity price levels. And those in many cases on inspection we found to be essentially artificial or economic shortages that could have been avoided with higher scarcity prices. And that's why we raised them.

I think that's sort of the principle that hits the core of your questions.

MR. RAMEY: In MISO I mentioned the tight operating conditions and the emergency operating procedures that our operators can follow to maintain operating reserves in the operating timeframe, including deployment of emergency resources, deployment of demand response.

It's been 2006 since MISO operations has had the need to deploy those types of resources. So notwithstanding, we've had several cases of operating reserve shortages over that period of time. So why aren't operators taking actions that they have available to them to mitigate these shortages?

Again, at MISO the shortages that we do have are primarily associated with short duration transient shortages. We're not getting into the emergency operating procedures in order to maintain those operating reserves over a long period of time, which you would expect that operator to do if that was a condition they were facing.

So having said that, we have encountered operating reserve shortages over the years, primarily driven by ramp shortages, and even generator contingencies. So if you lose 1000 megawatts of supply in operations even in a balancing area the size of MISO, that can drive you into short duration scarcity events.

Most often these occur in the summertime. So as loads are higher, the operating reserve scarcity we have, when we see spikes in a year, it's usually associated with higher load operating conditions.

2012 was really the last, July 2012 was the last really warm summer month that we went through at MISO. We had a number of operating reserve shortages, again short in duration.

Recently, so for the first time, polar vortex, cold winter operations this winter, MISO had a number--I won't say a number, it's higher than prior years but still way less than one percent of the total intervals throughout the year. So it was still a relatively small impact. But we did see an increase.

We had probably close to 50 intervals this winter where we had an operating reserve shortage driven primarily by unit performance. So as we've talked about elsewhere, forced outages in MISO were about two times normal winter forced outages we saw for many periods of this past winter beyond just the polar vortex the first week of January.

So those are the primary drivers of our shortage events.

MR. PIKE: So we looked at some data really driven by the four primary reliability-rule driven operating reserve products, and it's relatively infrequent.

So you're talking 50 to 100 hours a year you're going to have a shortage event affecting pricing there, and typically not for that whole hour. Typically you're talking about 10 to 20 minutes within the hour that the shortage prices will last for.

You know, in part I think that's self-fulfilling. Right beyond there is when we start having the ability to commit additional units to modify transaction schedules.

So you're going to see these events not last for hours unless you've really got region-wide shortage events occurring. Otherwise, you're relying on resource commitments, you're relying on pulling imports in to help resolve the scenario.

Regulation, because it's a lower demand curve value we will go short, about one to one-and-a-half percent of the time, and let those factor into the prices. Again, that's only an $80 shortage price at the low end of its curve, and that's typically what we're seeing.

One of the interesting pieces is certainly there's a concentration for us in the critical period operating conditions, the high-load conditions. But it's not all there. There's very much a distribution throughout the year that we'll see these events occurring.

Certainly in the off-load periods, the Spring and the Fall, which are more maintenance conditions, you're going to be operating a little bit on tighter conditions. And so you'll see these events occurring at those points in time as well, particularly if you're going to lose a unit in these times. Because there's less resources online then available to call on.

So not a lot. I'd say a couple tenths of a percent of the time for our operating reserve, one to one-and-a-half percent of the time for our regulation products.

MR. KEECH: Since PJM implemented its most recent set of scarcity pricing reforms in 2012, we've only had a couple days where we've seen shortages. And that was this past January 6th and 7th. The evening of the 6th and then the morning and the evening of the 7th for a total of about 10 hours.

One of the other unique things about PJM is we've have instances in the past, a couple of instances over the summer of 2013, most notably in September, where we've had market clearing prices that make it look like we're in a shortage but we're actually not.

We are using our emergency demand response and it's setting prices. So I think that's one of the things that was called out in the paper, which is that we get extremely high prices that make it look like we have a shortage when we use emergency demand response even though we're not technically short reserves.

So the total time period we had was about 10 hours. It was a couple hours in the evening on January 6th, about 5 hours in the morning and then about another 2 hours in the evening on the 7th. And those were the only hours we've had where we've actually been short reserves since we put that set of market rules in October of 2012.

MR. DILLON: And in Southwest Power Pool over the last roughly nine months, close to nine months, we are experiencing between one and two percent shortage pricing events.

And the one to two percent is primarily on the up direction. In other words, where you are trying to move generation up to offset something. And, yes, I've concentrated on the net interchange, but we also have 9 gigs of wind in SPP on a 46 gig peak.

And at three o'clock in the morning at this time of the year we're probably somewhere around 15 gigs. So we have 9 gig wind with a 15 gig load. And when that wind suddenly changes, all of a sudden we have to move generation very quickly.

So that's something else that impacts us in the Southwest Power Pool region. But again, it's--even after all that, even after the polar vortex which hit us--surprisingly hit us very hard, that was the weekend we started up the new market. You did not get any reports of outages, thank goodness. So it performed well.

Even with all that, we're between one and two percent of all the intervals.

MR. HELLRICH-DAWSON: Thank you. Operator actions, operator emergency actions have been mentioned a couple of times. I think somebody said that every single emergency action is priced in your market. Others have not spoke to it.

I wonder if you could just describe a little bit how each of you deal with those operator emergency actions. Maybe just give one or two examples, a couple of you could, that are ever taken.

And if you were to price those, if they're currently not, how would you go about doing that? How would you even determine what those prices ought to be? Richard, let's start with you and give Matt a break.

(Laughter.)

MR. DILLON: The one who obviously is searching his mind going, okay, which ones are out there?

(Laughter.)

MR. DILLON: We have so integrated items into the engine for dispatch and so forth that even an emergency action is a declaration followed very quickly by an instruction through the engine itself that results in, you know, whatever pricing occurs.

Now that emergency action may result in triggering scarcity pricing, because as you lose a 500 megawatt wind farm and have to move 500 megawatts suddenly into that space, even through emergency type action, then it will trigger scarcity pricing.

I honestly cannot think of an emergency action that was not coordinated through the market engine, either right before or immediately after the event was going on at this time.

MR. KEECH: So for PJM, I think we do a fairly good job of this, as well. When I think about walking through the emergency procedures that we typically would invoke on a peak day, emergency demand response that's eligible to set price and has quite frequently, in PJM when we deploy. So I feel like we do a fairly good job with that.

If we load max emergency generation, that also can set price. We haven't had an instance where I think we've loaded that and it set price, because we've had DR setting price at those times coincident. So that hasn't quite happened, but that capability is there.

Emergency purchases of energy can also set price in PJM just like any supply resource. And then we talked about the voltage reduction and manual load dump being forces into shortage pricing. Again, being a belt-and-suspenders kind of concept, if we have some data measurement error we don't want prices to be suppressed while we're in a voltage reduction.

Richard couldn't think of one, but I can think of one coming out of this past winter, which is during the polar vortex and also the winter storm later in the month, we had public appeals for conservation out where we feel that we've gotten substantive relief from that, as far as load perspective, but we don't know how to measure it. We don't know what the price value of that is.

And so we probably had lower prices because we had lower loads than we would have had absent that emergency procedure, but it's sort of a nebulous procedure where, you know, it's a public appeal and you don't really know what you're going to get.

You try to measure based on what would have been, but even that's a difficult thing to measure given the extreme weather.

So that's one that comes to mind. I'm not sure I have any solutions, but it's certainly something that comes up. But other than that, I think we do a fairly good job.

One of the other things that we're working on, and I mentioned the Energy and Reserve Pricing and Interchange Volatility Subgroup, one of the areas that PJM has room for improvement and where we're trying to improve is making sure we reflect in the market clearing engines what the reserve requirement is right now, and not what we carry on average.

And so a good example would be we procure 30-minute reserves in the day-ahead market based on an average load forecast error, and an average expectation of forced outages. That may or may not reflect what the operators are scheduling to today.

And under the current rules, we do not harmonize what the operators are scheduling today and that reserve requirement that's scheduled in the day-ahead market.

And so one of the initiatives we've got going right now is to make sure that our reserve requirements reflect what the operator wants to do right now, and the reserves they want right now, not what we use on average. And so that's an initiative we've got going on right now and we think that's going to be extremely helpful.

MR. PIKE: So I think our operators do everything they can to utilize the tools available to them in the market to solve their problems, to solve their reliability needs.

You know, one of the negative consequences of going outside of the market is it generates uplift, which was our first workshop, and in New York and I believe all the markets talked about this, that gets very, very close scrutiny every day to understand what those drivers were and what could have been done differently.

So wherever possible we're trying to leverage the markets. We're trying to leverage the economic scheduling of the transaction tools that are in place.

You know, I tried to go back and look at a few things. You know, the last--we've run one emergency transaction in New York in the last five years, and that was in the midst of Hurricane Sandy. So it's just not a tool that our operators are finding they need to go to. They can go to the economic scheduling of transactions rather than having to utilize that type of capability.

One area that we are looking at that I think offers a lot of promise is there are times where our operators will need to make supplemental commitments after the day-ahead market. Conditions have changed flexibility concerns about what real-time conditions will bring.

So we have within the stakeholder process right now discussions going on to increase our 30-minute reserve requirement, and that is absolutely intended to bring the additional resources online or available to our system operators so that they have that product already within the market and available to them in real-time. And it's really just a reflection that there are times where there is an increased level of uncertainty, and we need to have an increased level of resource availability going into the real-time markets to be able to deal with that.

And so that product discussion is ongoing right now with stakeholders. It would add another 650 megawatts to our 30-minute reserve requirement, and it would run day in and day out to be available there for our system operators. And that is absolutely a tool aimed at putting into the market those types of conditions.

MR. RAMEY: At MISO, each of these operator actions is identified as a significant opportunity for improvement in our price formation. Today, none of those kinds of activities are explicitly recognized in our price formation.

And I mentioned earlier that it's been since 2006 since we've deployed resources under emergency conditions. I should probably clarify. That's specifically related to NERC Level EEA events. So it's primarily deployment of demand response behind-the-meter generation that's available to us under those types of emergency conditions.

There are other operator actions that are relevant from a price-formation perspective that we have had to implement on rare occasions from time to time over the last few years. So we can get into a condition, just a market condition, where we'll declare a Maximum Generation Warning.

Even under that Warning step, our operators can take actions like curtailing nonfirm exports, directing external capacity resources to schedule into the market.

Today those actions are not well priced in our markets. Other actions, access to emergency ranges of generators, we can get the prices that are offered for those segments into our market construct, but often the numbers that are associated with those segments of generation are relatively low, reflective of perhaps marginal costs of production with coal. But the fact that they're emergency-only, you're only looking for those resources when prices are already probably in the several-hundred-dollar range. So you can get some price reversal in our market design from the release of emergency capacity.

So what do you do about it? One of the things that we talked about at the last session that I haven't heard mentioned here is MISO is moving forward early next year with the implementation of a new real-time pricing methodology called Enhanced LMP.

Under that initial implementation of our ELMP, it will include and pick up pricing impacts for category demand response we call Emergency Demand Response.

We currently have price offers associated with those types of demand response. We include them in ELMP. ELMP has a platform and creates the opportunity to think about including other types of operator actions in the ELMP formulation.

The other way to do it is to find a way to keep from shifting your whole supply curve to the right when you deploy some of these emergency resources. It's a challenging problem to solve, but essentially that's what you want to do.

At the time you're deploying emergency resources, you need a formulation if you're going to recognize those prices, or price impacts, correctly. And you need to keep all the deployed resources that are offered at--that are already dispatched to the market from sifting to the right, allowing the demand curve to come down and set a lower price.

That's a general description of the kind of design we're currently going through with our stakeholders and proposing for our emergency operating procedure pricing formulation that we're working through now.

MR. WHITE: Thank you. In New England, as I mentioned in almost the very beginning of this panel, we would turn to emergency procedures generally after we are already in a scarcity pricing situation.

Many times we don't invoke emergency procedures at all; we left the software resolve the problem. Operators may invoke emergency procedures primarily, and in summary terms based on the expected severity and duration of the condition.

When they do so, there are close to a dozen actions they can take. They have very detailed procedures that they follow and rules they use. Broadly you can characterize what they may do into things that increase supply, or things that reduce demand.

Things that increase supply include calling New York, which helps us out by sending control area power under protocols long established for that purpose.

Demand includes things ranging from voltage reductions, which is a more extreme measure in our system, or calling our emergency demand response participants to reduce demand.

They will affect prices. There's no question. Fundamentals of supply and demand. You reduce supply, or you increase demand, the price goes down. Nothing complicated there.

The question is: Is that the right thing that should happen? And one way, or the way I have tried to think about that is: Is the cost of the action we're taking less than the price signal we're sending to the market? And, of course, are the dollars going to the right people?

If that's true, that action is an economically sensible action. If it's not, we need to think about whether our prices are sending the right signals.

In some cases like requesting control area, control area power, in many conditions--for example, if New York was not in tight system conditions--the cost of that would be substantially less than the scarcity price signal we would be sending to the market. So that sort of all makes sense.

In some cases it's very hard to draw definitive conclusions. Is the cost of a five percent voltage reduction for half an hour in New England more or less than the costs of the price signal we're sending? Those aren't even measured in the same units. One is reactive power; one is real power. It's very hard to sort of come to firm conclusions on it.

One area where we've made a lot more progress is on emergency DR, what was formerly emergency DR. We went through a long process, and filed, and the Commission approved rules in which DR when called--I'm sorry, DR will be obligated to offer into the energy markets and becomes eligible to set price, and in so doing when they are called they would set price at whatever they offered.

Those rules are still pending implementation, but that is one means by which one can avoid, Todd called it the price reversals or price crashing, if you take an action like calling on DR and those participants have very high costs of reducing their load, and you want the cost of that action to be appropriately reflected in prices.

So there are methods to deal with these. None of them are simple. And as I think our experience getting those rule changes for DR through indicates, none of them happened very quickly either.

MR. HELLRICH-DAWSON: All right. Thank you.

I want to change gears a little bit--sorry, do we have a question?

COMMISSIONER MOELLER: Yes. Can I ask Adam to elaborate a little bit more on your initiative that you talked about and the timing of it?

MR. KEECH: Are you talking about the Energy and Reserve Pricing in Interchange Volatility Group?

COMMISSIONER MOELLER: Specifically having your operators have the ability, real-time, to I guess deal with the operating reserves as you elaborated real-time versus projected? You can say it so much better than I.

(Laughter.)

MR. KEECH: So I think that is that group that you're talking about. So that group has worked probably since coming out of the summer of 2013, winter of 2014 certainly added fuel to the fire for that group, and currently the two proposals in place are this concept of augmenting the reserve requirements in real-time based on the operator's needs. And then, having some provisions to minimize the impact of interchange swings at the peak.

Those two proposals will get voted at our Members Committee--I'm sorry, Markets and Reliability Committee meeting on Thursday. And then finally they'll be voted in the end of November, sort of a final approval.

So the intention is to implement those practices by this coming winter, January 1st.

COMMISSIONER MOELLER: Oh, terrific. Good. It seems particularly relevant. And is that applicable in the other markets as well?

MR. RAMEY: If I can jump in and speak for the MISO market, which had a very similar operating experience as PJM had this past winter. As I mentioned earlier, that in MISO our forced outages or unavailable resources was twice what you would expect on a normal winter day.

So the question is, as Adam characterized it, you kind of plan for your operating reserves and your commitment criteria day-ahead, and even post day-ahead with some more forward reliability commitment assessments based on average expectations of unit performance.

And so a question in MISO came up, as well: How should we think about that? If 20 is normal and I know I can have 40, as an operator how do you think about that in the context of your market design?

And we have wrestled even with stakeholders and are still wrestling with this a bit: How do you do that?

If the real issue is a failure to start performance problem as opposed to higher levels of instantaneous loss of generation that's online, you'd have different solutions for those.

We're still analyzing some of that data from last winter, but it's starting to look like the driver was more of a fail-to-start problem. So it's a fail-to-start problem, increasing your operating reserves day-ahead is probably not going to help that problem because operating reserves are there to handle the instantaneous loss.

So then you get into some discussions around as an operator I may make some more conservative commitments and anticipate that I'll have more units than normal that fail to start. There's not a real easy way to fold that into the market design and price that.

So we're having those conversations with both Reliability groups and Market groups in MISO now. At a minimum, if we anticipate similar conditions, operators will take conservative actions to make more unit-start instructions to go out in anticipation that you have a higher level of failure-to-starts.

The downside would be is if you're wrong and everyone performs, you've got an over-commitment problem with potential Uplifts. Our reliability folks say that's the cost of being reliable.

(Laughter.)

MR. RAMEY: So, yeah, that's the way it works. And I've tried that with my Board when they ask why Uplift was so high, and they're maybe a little tougher to convince sometimes.

(Laughter.)

MR. DILLON: In regards to Southwest Power Pool, I guess being the last sometimes means we get to learn from others. And we have. There's a balance. There's always a balance if you work things out.

Our specific Tariff allows what's called "headroom." And there's a calculation methodology, and there's a check and adjust, and it's to allow reliability to say I need this much excess generation above and beyond the reserves.

That can also be overridden by the reliability operators--they need to explain why--in real-time, and bring more generation on. Right now we're holding about 1500 megawatts above and beyond the reserves in real-time for normal operations and coordinate that.

So the check is it can't just be any number, and we have to report out on the experience to the stakeholders because it automatically results in Uplift, just automatically. But when we need it, there's already a procedure that allows the reliability guys to go ahead and bring things on.

MR. QUINN: Can I ask a follow-up? If those operators decided to acquire additional headroom but then went short of that additional headroom in real-time operations, would that invoke scarcity pricing for you all? Or do you have to get through kind of all the headroom you've got before you would then experience a shortage pricing event?

MR. DILLON: It, it--as I recall, subject to check, but as I recall it, we have to get through the headroom before it hits it. Because we're basing it upon the capacity requirements for the reserve products. And the headroom is above and beyond that.

MR. RAMEY: If I could follow up on the headroom issue, that's an issue at MISO as well. Headroom, as you analyze it at least from our analysis, headroom is a commitment of capacity above and beyond your expected total requirement of energy in reserves. So why would you need that?

Really, what headroom is is we analyze it as the proxy for rampable capacity. If you need to be flexible even in the operating timeframe, and flexibility looks like moving generators around to accommodate changing circumstances, you need unloaded, uncommitted capacity that you can ramp.

So as we look at headroom at MISO, it looks like a ramp proxy. So one of the things we've look at in working with stakeholders who made a filing is to implement a new ancillary service. If that's really what it is, a service that's needed by system operators that looks like an ancillary service, you can build a ancillary service product for rampable capacity. And so we'll be adding that to our market mixture as well.

We think it will help price some of that headroom driver. And headroom is directly related to the amount of ramp you know you'll need. So winter morning between hour ending 8:00, I know at the beginning, 8:01 and 8:59 my load is almost 5000 megawatts higher at 8:59. I need a lot of headroom that I've had to precommit in advance of that hour just in order to handle that ramp of that load pickup.

In a flat hour in the middle of the day, you need half as much headroom on the system operator reliability. so the value of that ramp proxy changes throughout the day as well.

MR. PIKE: Yes, I think that's really an interesting question. The optimization tools that we all run are really, really effective at giving you just what you need, just what you asked for.

They're designed to minimize the cost, and so they're going to give you exactly what you need and not any bit more. And that's, you know, not leaving any flexibility, not leaving yourself any option to be different than what your day-ahead market predicted.

That was a large driver in our increase of the 30-minute reserve requirement proposal that's in front of stakeholders, is to say that, you know, we're not perfect in our forecasting capability. What do we do to get that additional flexibility within a market construct so that it's there and available to the operators so they can commit it. It's there, and it's available in real-time?

The important lesson we learned from last winter, as well as you now have got a financial obligation, you now go out and make sure you buy the fuel that you need to run that resource in real-time if it's there. It could be quite expensive to buy the product on that winter day, but if we need it we're going to be very happy we spent that money to get the resource available and for him to have procured the fuel that he needs.

MR. WHITE: Commissioner Moeller, I think I don't know quite enough about how Adam's system works to comment directly on it, but something that may do largely the same functionality and which we've found to be quite important in the last two years, particularly in the winters, we have something called "Nonperformance Adjustment Factors" in our reserve requirements each day.

We do detailed studies at the individual generating unit level for many of our generators on exactly how well did they perform when we tagged them with reserves and we asked them to go? What did they do? We track it over time.

And with all that statistical information, we aggregate it--in addition to telling the laggards, hey, do you know about this, it's a concern--

(Laughter.)

MR. WHITE: --we aggregate it up to the system level, and then we adjust our reserve requirements by the aggregate nonperformance we have seen in the hard data over the past study period.

We update that regularly. That may--the current factors are somewhere between 20 and 25 percent, so we would have for example our 10-minute product. We might have 10 to 25 percent more reserve requirement during the operating day than the nominal NERC standard we need to honor. So that the expected amount of energy we will get if we tell them all to go is actually what we need to recover the system.

We find the system has helped a lot in making sure that what we expect to get is in fact what we do get in time. We also share that information with the affected units, and we've found that process to actually, coincident with us instituting that process in the last several years, and sharing that with individual generators we have seen many of those resources' performance improve significantly after we started putting a spotlight on this and the importance to the system.

It also, I think to the question you were hitting at, means when we need to have more resources on, that additional nonperformance adjustment boosts our reserve requirement not just in the forward reserve market, which is unique to New England, but also in the day-ahead commitment process, and in the real-time operating process.

There's no headroom before we hit scarcity pricing. So once you've raised that level, we've accounted for those additional commitments--to the extent we've accounted for the additional commitments with that additional nonperformance adjustment, we would hit scarcity pricing as soon as the reserves dropped below the nonperformance adjusted reserve requirement.

MR. HELLRICH-DAWSON: Okay. We're at 10:30, and I'm actually going to hold you all here for another minute to ask another question that I wanted to cover, and that regards coordination across borders.

We've seen some instances where the timing of the price signals that are sent out and the scheduling of imports and exports can lead to sort of weird results. MISO and PJM I think you've experienced this in the past during emergency.

Is there a way to improve that coordination across the seams? This coordinated transaction scheduling, for instance, would that help? Or do you anticipate it helping? Is there something else that could be done to improve that coordination specifically during emergencies?

MR. KEECH: You commented on coordinated transaction scheduling, and I think that will certainly help. But I think the real issue that we come down to is we allow a lot of flexibility with interchange, and we send out prices that say this is the value of the interchange, but we don't ever say how much is valuable.

And so we might say at this interface it's $1800, but if that's 6 megawatts and I get 500 that respond, that becomes problematic at that point.

So one of the issues I think we run into, and maybe the primary one, is there's not enough information out there to tell the market what sort of the saturation point for that interchange is. And maybe that's too complicated of a problem and it needs to be sorted out between the two neighboring regions, but I think that's a lot of where we get into the problem. Because you would think if only 6 megawatts would warrant an $1800 price, we wouldn't get 500 if people knew that.

So I think that's one of the issues that we run into, at least from PJM's perspective. Certainly we've seen that on the PJM-MISO border. I expect the coordination, like CTS, to help. And wherever we end up with the MISO version of CTS in a year or so, I expect that to help as well. But at the end of the day, those are also voluntary products.

And so the ability for the 20-minute interchange to come in and sort of, I don't want to say trump the scheduled interchange, but come in in addition to the scheduled interchange still is going to be an open issue out there.

MR. RAMEY: Like many of these design details, it often comes down to how big of a problem it is. And this question of interchange scheduling between MISO and PJM is a relatively big deal.

There's lots of transmission that connects these two markets. There's lots of surplus capacity available from time to time to move between the markets. And these pricing mechanisms can create substantial price difference between the two RTOs.

And the current paradigm on that seam that provides for market participants to be 100 percent responsible for requesting an initiating those transfers on that interface where you can have plus or minus 4000 megawatts move in a pretty short amount of time, given the price differences you'll get a lot of movement.

And as Adam described, the challenge with that paradigm and why it's a big deal given those volumes on that seam, is that market participants do not have enough information to know how to optimize that.

As Adam described, they don't know if it's a 100 megawatt problem, or whether it's a 500 megawatt problem, and so the volume of the transfers is just proportional to the price differences.

And by definition, my experience is, they will get it wrong. So in my opinion, at some point I think you can do both; you can allow for a high degree of flexibility of market participants initiating those transfers up to a point, but I think for this to work well we need to get to a design where the RTOs that have the information on both how much supply is needed and how much to transfer--it's essentially the surplus supply and demand curve that we can share. And if we can minimize the participation and activity of market participant-initiated transfers in a pretty tight timeframe around real-time operations, maybe within a half-hour ran or an hour, and limit the market participants' flexibility, I think that's what's going to be needed for the RTOs to rationalize the price formation and to rationalize those transfers close in.

MR. DILLON: I guess I'll have to jump in. Todd mentioned something. One of the parties that's not at the table right now is CALISO at this table. And CALISO moved towards a more restrictive interchange scheduling. It's either an hour or two hours ahead lockdown.

Whereas we tend to be more on the flexible side of allowing as long as it hits the NERC timing. And observations on the CALISO is that has also resulted in some strange market activities that go on decisionally because the parties that are outside do not have the ability to make modifications once they're in the lockdown period.

I do not have the answer, but I do know that we have two bookends of one that is fairly restrictive, and then most of us on the Eastern Interconnect, which probably SPP is the easiest one, that you literally could change your interchange schedule every minute as long as you can hit the NERC timing for approval, the 20 minutes before initiation.

And the answer is somewhere in between. I cannot tell you what the answer is right now, but I can say that we can look at the two cases on either end and see is there somewhere in the middle that we could meet.

MR. PIKE: From New York's perspective, we haven't observed or experienced the same level of volatility that's happened between PJM and MISO.

In large part I think that's due to the

scheduling tools in New York that are looking at economic offers for all imports and exports. There are bids and offers for all. Those are factored into the dispatch and the commitment decisions made when we've scheduled those transactions.

So I think we take account of the New York economics at least and the deflection in the supply curve that happens when we add imports and exports.

But Adam and Todd raised, you know, a really significant point, that there is not that level of information to the traders out there to know just how many megawatts need to move. They don't have the supply curve, nor can we give it to them. That's not information we would want to provide out there.

You know, Matt and I in our early discussions of coordinated transaction scheduling between New York and New England, this was absolutely one of the drivers that said, you know, the status quo can't continue to work. You have to build a new product in order to get the economically efficient schedules.

And that's where CTS came from of looking at the difference in prices, the sharing of prices between the two regions, and the scheduling of a transaction based on the delta in price so that you can see the deflection. So when you add that 100 megawatts you see the prices have changed and you stop scheduling more transactions.

So I'm absolutely an advocate that CTS will greatly help the scheduling. It won't be perfect. It's still a forecast of prices, but it will be a significant advancement over where we are today both with New England and PJM.

MR. WHITE: I would just briefly second essentially everything Rob has just said, including the fact that we have not seen the concern with energy volatility in New England that has been expressed by some of the representatives from other regions, largely for the same reasons Rob just mentioned.

Nonetheless, we did think that improving interchange coordination was a priority for us. And about four-ana-a-half years ago, as Rob mentioned, we started work on CTS.

The connection between that and the core questions in the previous observations is, what CTS does, one of its key elements, is instead of simply having participants see the prices in each region, or their estimates of the price in each region and have to make a guess as does it take 5 megawatts to drive the price to parity, or 5000 megawatts to drive them to parity? And if it's only 5 and they dump 5000, suddenly the prices go all the wrong way.

CTS takes the participants' bids, but then integrates them with the ISO's internal knowledge of our supply curves to determine how many bids clear, and what the interchange schedule should be for the scheduling 15-minute interval.

And that way, because the ISOs have all this information about the scheduling, the supply curves, the deflection that Rob mentioned to you is, we can see. Oh, it looks like you want to have exactly 400 to converge the prices. Oh, no, you want 5000 to converge the prices. Or you only want 5. And that's of course what goes.

So those kinds of innovations can in principle help greatly with this. I think Rob and I are both cautiously optimistic that when it goes live we'll see exactly the performance that we expect.

MR. HELLRICH-DAWSON: Alright. Thank you very much. This has been really informative.

Let's take a break for just 10 minutes and we will regroup for Panel Number Two at ten minutes until 11:00. Thank you, very much.

(Whereupon, a recess is taken.)

MR. HELLRICH-DAWSON: All right, welcome back. This is the second panel of our shortage pricing discussion this morning.

We are joined by some representatives of both load and generation, as well as market monitoring. Let me go ahead and introduce everybody, and my apologies if I get your name pronounced wrong. Please correct me.

Joe Cavicchi from Compass Lexecon, right, speaking on behalf of the Electric Power Supply Association.

Erica Bowman from America's Natural Gas Alliance. John Citrolo from PSEG Power. Charlie Bayless from North Carolina Electric Membership Corporation. And Joe Bowring from Monitoring Analytics.

Thank you very much for being here. Excuse me. My cough seems to be getting worse.

One of the first things we talked about this morning with the RTO and ISO representatives, who by the way, some of whom, are over here to the side.

(Laughter.)

MR. HELLRICH-DAWSON: What the goals are of the shortage and scarcity pricing rules. And if you could, I'd like to go through the panel here and have each of you tell us whether or not you think that the goals that were described earlier are the right goals; whether or not you think the goals ought to be different, and perhaps how you'd go about making those changes and what those changes should be.

So can we start with you, Joe?

MR. CAVICCHI: Sure. So I just want to say thanks to all the RTO and ISO representatives. As you said, Bob, it was really informative to hear from everyone.

I would say we at EPSA, we certainly generally agree with the goals that are articulated. The shortage pricing/scarcity pricing frameworks ought to have as their objective producing prices that rise during times of scarcity or shortage.

I think some of what we heard about tells us that there's a lot of complexity in how you actually achieve that. I think that the ISOs and RTOs are focused on the short run. However, when we talk about the prices that they're setting at, their prices are somewhat, I mean, for most of them based on sort of avoided costs of generation resources at a particular time, as opposed to taking into account the value of lost load or what the cost of an involuntary curtailment might be, which would change significantly the behavior they'd get in the real-time market.

At the same time, I think there was some suggestion on the longer term that the ISOs with capacity markets probably were getting solutions in the capacity markets for the most part that were consistent with their objectives.

I think we'd argue that the shortage pricing and scarcity pricing is a very important complement to the capacity markets in that not all new capacity even that's being built now is really created equally. And they won't all have the ramping capabilities that we're talking about unless they actually perceive in the marketplace there's value to it.

And I think investors will go through the electric power suppliers and think about what those values are. So it's very important that in both the short run and the long run we get the prices right, and thus we'll hope that the signals will then get to the investors, the signals that are necessary.

Thanks.

MS. BOWMAN: So thank you for having me here. We probably agree with a lot of what Joe just said in terms of making certain that the prices are right during scarcity conditions. But also allowing for the scarcity conditions to exist so that the value can actually be attributed to that for the resources of providing power during the times you're providing reserves.

I think one of the issues when we look, coming from more or a natural gas perspective, and as we have a lot of conversations around natural gas and electric coordination, there are questions in the wintertime--and certainly this last winter has highlighted that--around fuel reliability and how can you encourage that those fuels will be there during very high demand times for that fuel? And when it coincides with high electric demands, or it coincides with electric issues at the generator level because of outages.

So I think, you know, there's a whole host of revenue streams in these markets that help to solve that problem of making certain there's enough revenue for generators to achieve not only their distance in the marketplace but also a reliable--providing a reliable product.

And so I think ancillary services is one of those areas that if you get the value correct, you might be able to encourage more investment in that firm fuel that a lot of ISOs and RTOs are looking for. Because you'll see that price incentive, and if you're not operating at that time it might encourage you in the future to either procure contracts that allow a firm fuel delivery, or maybe build additional fuel storage, et cetera.

Thank you.

MR. CITROLO: Good morning. First of all, I'd thank you for letting PSEG Power be represented here today.

Our ultimate goal is to preserve capital traction to the industry. I think if you look at the top three industry with capital needs--you look at the Federal

Government, banks, and the utility industry including the power side, power generation side--and if we look at what happened to the first two that I mentioned, we definitely have a concern about that.

One of the goals that we think to meet that would be to preserve the integrity of the two settlement systems, which we don't believe we are seeing each and every day. The day-ahead market obviously to preserve financial security for both load and supply, and in the real-time market should reflect the conditions of the system.

Units that are following dispatch should be reflected in price. First let me say that PJM has done a tremendous amount of work to solve some of the issues we had around the, what I would call the side effects of shortage pricing in 2013.

We disagree on a couple of points, but what the ultimate objective should be--and I'll use one example, would be the interchange pricing. Currently interchange units can schedule 20 minutes before the interval. They come on at the bottom of the hour. They take advantage of let's say the first six or seven high prints of the hour.

PJM is working to correct that by increasing the timing and limiting the amount of interchange. We think ultimately the goal there should be to have a less-than-hourly integrated price. Because even if you solve the interchange problem, you still have units internally that may be chasing LMP. And that's certainly price-suppressive.

And that's just one example. But ultimately, like I said, overall it's the price suppressive actions that we feel are being administered to control price volatility that are actually hurting the industry.

We're seeing a lowering of the forward energy curves. We need those to be accurate. They are based on a real-time price to preserve capital traction, like I said, which is their ultimate goal.

So thank you. I'll stop there.

MR. BAYLESS: Good morning. I think the goal of shortage pricing is to show the price of energy leading up to and during shortages. And for half the market this probably works fine. For the generators, they get to see the real-time prices and can react to them.

But half of the market is left out. Customers do not get any real-time price signals. They see flat price, flat supply curve at all levels, and are not able to react to price whatsoever.

Because of this, during shortages when you hit the very inelastic part of the demand curve, prices are really bid up and you need more and more demand to--or not more demand, a higher price to incent more generation to come on line.

And all at the same time, all customers see is a flat price and they're unable to really react to this. And it's because of the, some people call it a market, but it's really a market construct. It's not a true market, since the two sides cannot see the price and react accordingly. Only one side can see the price.

So we see this as a sort of regulatorily created problem that causes--requires a regulatory solution, which is price caps and mitigation measures to ensure that, you know, prices do not escalate too high during these shortages beyond a reasonable point, basically.

And I think there's one other cause: fuel diversity. There's a number of factors that lead to this. Some of it's environmental changes, but part of shortage pricing is also leading to gas-peaking units.

And with the prevalence of renewables and gas-peaking units going on, there is less and less fuel diversity in PJM--well, in the system in general. And it's very hard to plan for a 1-in-10 loss of load on a fuel source that doesn't have a 1-in-10 loss of load, as seen in New England and parts of PJM this winter.

When you come--when fuel or gas gets very short, it causes shortages that bleed into the electric sector and can affect price. So there are really two factors there that are pushing on price signals that consumers do not see.

So I think we really need to look at this as a regulatory problem with price spikes, and have caps in place for a regulatory solution.

MR. BOWRING: Good morning. Thanks for the opportunity to talk to you today.

Just at a high level, shortage pricing is an alternative to, or really a complement to capacity markets for solving what we refer to as the missing money problem. And the performance incentive problem.

There are really two ways to do it. They can do it separately. They can do it together. In my view, the best way is if they serve as complements. But both are administrative approaches.

I think we all understand that the capacity models in markets are administrative and to a substantial extent, although they're using market mechanisms. But shortage pricing is also administrative. It's not some magical laissez faire approach through handling these issues, it's very much administrative.

The frequency, the duration, and the price level are all administrative choices. And all should be made with an eye to the goal, whether the goal is the entire source of revenue sufficiency, or only part of it and in significant part to provide performance incentives.

Capacity markets I think are a more stable and less volatile form of scarcity pricing, but that's why I say that together they can complement one another. I think it's a reasonable long-term goal to attempt to increase the level of revenues in the energy market, although some of the new scarcity--I'm sorry, some of the new capacity market designs are helping to address that. But only if the problems with scarcity pricing can be resolved. And in particular the net revenue offset work appropriately with the capacity market, because that's really the mechanism by which they complement one another.

So I mean I have various comments on things that were said this morning and other details, but that seemed to me to answer your question. So thank you.

MR. HELLRICH-DAWSON: Thank you, everybody. We've just got I think four people at least who said that they don't think necessarily the markets are working the way they ought to in some way or another, but one of the things that struck me is we have wildly divergent views up here on what the right price ought to be. And I know during our capacity markets technical conference, which has been about a year ago I guess, there was a lot of discussion about if we get the prices right in the energy and ancillary services market, we don't have to rely on the capacity market quite so much.

Can you just describe for me a little bit what you think those right prices are? I heard value of lost load, but I also heard price caps. How do we figure that out? Where should that price be to be, quote/unquote, "right"?

Go ahead.

MR. CAVICCHI: Well as you suggested, it's not something that's easy to answer. I guess we'd observe the following.

There has been a lot of research on value of lost load, especially in recent years. I think there's a much richer database of analysis now that tells us a little bit about what the preferences of customers would be when faced with higher prices.

Now the elasticities of demand are not high, by any means. We all understand that the elasticity of demand for electricity is low. However, with some indication of what lost load is worth, and factored through in some way to shortage pricing which from all the discussions we heard today is truly a situation where the ISOs are operating say closer to losing load than they would otherwise be operating, setting aside particular details about how they get there--I think that's a different debate about how you get to the shortage situation--it seems logical that you could have shortage pricing that moved on some schedule that was based on reasonable expectations of what the value of lost load is and not necessarily--and I think this is important--not necessarily what the cost of the most expensive generator is that's being dispatched given that shortage pricing is a proxy for scarcity.

Scarcity, for most economists, is included in short-run marginal costs when supply is tight. So I think if you kind of look to the studies as indicative of what might be appropriate, I think we'd all recognize we're not talking--and I think we heard this morning--we're not talking about prices being set with great frequency or for long periods of time.

I think what we're really talking about is the signal that the real-time market ultimately sends back into the forward markets that then get us to the point where consumers are hedged in some way.

It may not be, as Charlie described, through a wholesale entity, which we often see, who actually takes actions then. And those actions ultimately are the actions that help support investment.

Thank you.

MS. BOWMAN: So it is a very difficult question to figure out what is the right price. And I think that it's also very difficult given where we are today, thinking about all the different changes that we've undergone currently in the U.S. energy structure, as well as upcoming changes that have been proposed certainly at the EPA level.

So there's been a lot of change in the marketplace. Now there's a lot of, you know, the RTOs/ISOs are very focused on reliability as they should be. That is their goal, to keep systems reliable.

You have different environmental rules coming online, or are being proposed that aren't as focused on reliability. They're focused on cutting emissions. And then you have whole different sets of fuel sources available to market participants, whether it be a new abundance of natural gas or it be renewable technology.

So it's creating a lot of different dynamics that is I think leading to questions around, okay, are the markets we currently have today, and the market rules, and how they kind of create the ultimate price formation for what a generator will receive to serve load, how much--is there still missing money present in the market?

And if there is, what is leading to that missing money? And I would argue that there are things that may need to be done on the capacity side if you want to make certain that you have your firm winter product, as well as a firm summer product, that you may need to incorporate additional costs so that when you calculate your net cost of entry it may be a different number today. It may be higher because you may need to include that firm fuel in ways that haven't been included before.

On the ancillary services side, I think having these kinds of conversations are certainly helpful in trying to understand where are there new, like MISO was talking about, possibly a new ramping product.

Where are there new issues that are developing that there needs to be a new product to address? Such as renewables and intermittent resources that really do go offline pretty instantaneously and you need to have resources there to pick up the slack.

What kind of value do you want to assign to those units that are able to provide that flexibility? So all of those combined I think gets you to the right price formation. And again, with loss of load too. I think load should be part of the conversation.

What is the value load is providing? Or giving to that supply? And are they willing to not take that supply in order to avoid the price?

So these are all good questions. I do think that it's very unique because we're sitting at a time period where there's just a lot of change happening in a lot of different areas of the energy sector.

MR. CITROLO: Yes, thank you.

Actually I agree with my colleagues here, the first two. There's no silver bullet I can give you to solve the problem today.

I can point to one thing that I think is important, and that is: transparency with regard to operator actions. There are times where the operators are forced to override perhaps what the system algorithm has kicked out to them.

And please don't hear me say that we're asking, for my example, PJM, to change necessarily the way they do things to preserve reliability so I can make more money. That's not what I'm here to say, despite the fact we have some disagreements with them. We want them to be able to do what they feel is best to preserve reliability. We just ask that it be transparent so that we know in fact if one operator is going to call 5000 extra megawatts to preserve reliability versus the next day someone's going to call 10,000 megawatts to preserve reliability because they feel they needed a softer cushion.

So we've seen instances where the system is just running way too fat, but at the same time PJM has worked over the last 6 or 8 months to address that problem.

I could give you a couple of things, since I really don't have that silver-bullet answer, that are signals to the market and marketplace that affect things like the forward curve that undermines our ultimate goal, which is capital traction.

For example, the hottest week of last year in PJM we saw regularly the real-time price settle below the day-ahead price. We saw a market heat rate of 3500 MMBtus. So that's perhaps a sign of the virtuals displacing the price of generation, but we still actually need that generation to run and it's not being reflected in price.

So for example if 95 percent of the time I think last year based on a State of The Market Report, a virtual transaction set the marginal day-ahead price. Later in the day, PJM then needs to strip those out and recognize what actual generation needs to run to meet forecasted load.

Those units need to set price. Whether they're considered inflexible, which is kind of an ugly word being a generator, but that's how units are characterized, particularly CTs, that have an eco min equal to their equal max.

But those units are called. They are needed to meet reliability, and they should be reflected in price.

The second thing is, we don't think--and we see some evidence of this of the RTO feels it necessary to control price volatility in the real-time. They don't want prices to rise too high. It attracts self-scheduling, which ultimately suppresses price and may raise Uplift.

But at the same time, they also are focused on convergence of the day-ahead and real-time market. Those two things we think should be kind of outputs of a proper modeling of the day-ahead and real-time market. They shouldn't be the primary objective.

So we've seen price convergence in PJM with evidence of that, but those prices are converging at too low a level because we don't see system conditions always reflected in the real-time price.

And like I said, the hottest week of last year is probably a very good example to look at for PJM. At the same time, I do want to recognize PJM taking a lot of corrective measures for some of the side effects we saw last year where we had no shortage conditions.

We had a very hot summer. We had a hot fall. We didn't have any shortage events, with the exception of one zone. Now this year we did have two events in the wintertime that we feel did reflect system conditions.

So like I said, I don't have that silver-bullet answer, but there are signals in the market that we feel are erroneous or inappropriate and they're dampening the forward curves which ultimately the energy market is where we attract capital.

The capacity market is to preserve our fixed costs, incent new generation, but at the same time to actually grow the business and, as I said, attract capital for new investment.

The energy market is equally important. So we do feel that proper price formation in the real-time market is as important as proper price formation in the capacity market.

Thank you.

MR. BAYLESS: Shortages don't happen very often. I think, if I remember correctly, the staff white paper that was put out last week said in PJM there were no shortages in 2010, '11, and '12, and 3 days in 2013. I think I got those numbers right.

But that's basically three days over a four-year period. So this is something that really doesn't happen very often. And I don't think that it really sets much of a basis for economic decisions on building generation. You know, at least for our company we are not basing the building new generation on something that happens three days in four years.

Or we are looking more at long-term price signals. And I think the data proves that. I think the APPA study that came out a few weeks ago says that in 2013 that 60 percent--66 percent of the generation that was actually built had a long-term power purchase agreement associated with it. And 33 percent of the generation was built by a utility for their own needs. And only 2 percent of the generation that was actually built was built to bid into a capacity market.

So there seems to be long-term price signals, like purchase power agreements, or your own self-supply, that are incenting new generation to come online. And these short-term price signals that mainly account for a few hours a year, you know, really aren't moving the market.

MR. BOWRING: So clearly there's no right answer according to the RTOs and everyone here. What a surprise. But that doesn't mean we can't think about it rationally, and clearly--

(Laughter.)

MR. BOWRING: --put some bounds on it, right? I mean, it's not a million dollars and it's not zero. So we know there are some bounds on it.

But even more narrowly than that, I mean you have to think about what the goal is. The goal is two-fold. The goal is incentives to respond, and I think the earlier panel did a good job about explaining exactly why those incentives matter. And sometimes it's 5-minute intervals, sometimes it's slightly longer intervals.

So the incentives matter, and the revenues matter. It depends on to what extent the market is relying on those revenues to really solve the missing money problem, or whether it's really primarily about incentives.

But in either case, the number has to be high enough to provide incentives to generation to respond in real-time when the system needs it, but not so high that they vastly exceed that requirement.

I don't think anybody really knows what the value of lost load is. So I mean it's, you know, again important to think about the level of the price and what that means to load. But the actual value of lost load, as we know, is all over the lot.

I haven't really heard of any reasonable objective basis yet from any of the RTOs for setting a scarcity price. I think it's a matter--it's a matter of judgment. It's a matter of judgment formed by the purpose, and those two purposes again are really the incentives and the revenue.

So I think that the RTOs will all come to slightly different judgments about that, but they're all within the range of rationality.

MR. HELLRICH-DAWSON: Let's talk about--Erica, you mentioned price suppression earlier, which I take it to mean you think that shortage events are not being--or shortage pricing isn't being invoked often enough, or when it should be? Did I take that correctly? And if so, could you expand on that a little bit and talk about what changes you think ought to be made in the RTOs?

MS. BOWMAN: I don't actually know that under current conditions that the prices are necessarily being suppressed. I think the questions go to--the question really becomes: When is shortage pricing being invoked? And I think the ISOs and RTOs answered that question pretty well in the last panel.

I think as another reason, though, why we're probably not seeing a lot of scarcity events is the fact that we are still--a lot of areas have a very large reserve margin today, although that is declining as retirements happen over the next couple of years due to different market forces.

I think as we move into years that we may see higher scarcity because the reserve margins tighten. I think the concern, at least, is with that increased volatility will there be more pressure because it's different than the past, that there needs to be changes that would lead to set price suppression going forward.

And that's something that I don't think that volatility's necessarily a bad thing. It's giving price transparency. It's showing where things are needed, what kind of resources are needed, especially if you have different kinds of products out there to help attract certain kinds of resources.

So it's more of I think a cautionary thought around, you know, as we transition into a new world in a lot of ways of operating, and we may start entering into new dynamics of volatility, I think allow that to happen. Obviously monitor it, make certain that the volatility is happening for a reason and not because of market power issues, but see what kind of investment comes from that.

Because I think people will respond. I do disagree--I think that ancillary services do provide--it could provide a price signal for long-term investment. Obviously the level matters, and how much that kind of comes to in coming years.

Maybe there's not enough scarcity out there to really incent it. But if there is, that gets baked into the forward curves and people make decisions off those forward curves. So I do think that it does matter to get these markets correct.

MR. HELLRICH-DAWSON: Joe Cavicchi, could you speak a little bit about whether or not those shortage prices, those events, that revenue that's expected from that, gets built into that, or how it gets built into that investment decision? And then, John, if you could follow up also?

MR. CAVICCHI: I think it gets built into the investment decision as an ancillary reserve stream that is probabilistically estimated. I don't think it's a big revenue stream, but I think it's enough of a revenue stream that if you're building a gas-turbine-based type plant, which we're going to see a lot of, you may make decisions at the margin about how you fit that plant together.

So for example, you know, these things, the duct burners you put in to get extra supply out of the plant in certain instances can be something that can provide you ramping since they're quite controllable, if you've ever actually looked at them.

The kinds of machines that you actually buy, some of them now are really super high efficiency. And I don't see these companies running these things up and down, or ramping.

At the same time, so in that regard it adds value. But does it drive the whole investment? No. But should it be in the forward price? The answer is, yes. I mean forward prices are based on expectations of future spot prices. That's really the way it works. And anyone you talk to thinks about it that way when they're estimating value.

One example I think that's interesting about how some of this can matter is, one of the plants in Maryland, Morgantown, made investments to improve its ramping capability. And it didn't seem like it was a particularly complicated project, but my guess is that they probably saw some value in being able to ramp, given that the market was changing, and they took action.

And if my recollection is correct, they increased their ramp rate by several times by making some changes. So I think it gets thought about. And then it factors in. But I would agree, it's not going to make--to Charlie's point, it's not that we're saying that's what drives the investment. It's more important to think about what investment you're going to get, and will it factor into the decision making?

MR. CITROLO: Yes, it may be a little perverse in the way things actually work, because as a generator typically we're paid the day-ahead price. So you can ask why am I focusing on a real-time price.

For whatever reason, the investment community focuses on the forward curves for energy that are based on the real-time price. That's why we feel price formation is important.

At the same time, there is an ability to take risk in the real-time markets. For example, we have an interday trading desk that provides ancillary revenue, and I think the investment community looks at that as well. And when you suppress price in the real-time market, you really pinch the returns in that market.

The second thing would be our concern with, if an

RTO is trying to control price volatility, as Ms. Bowman referred to, price volatility is not necessarily a bad thing. In fact, it can drive investment.

Because if the RTO is trying to control price volatility in a real-time market artificially--for example, if a load-serving entity goes naked into the real-time market and they feel an obligation to protect those entities. We don't think that's right. Risk equals reward, and you get that in the real-time market.

So you shouldn't try to transfer risk away from the real-time market if entities decide to take risk. And I think investors focus on that, as well. You know, increased risk equals increased reward.

So if a company has the ability to take advantage and is able to wear the risk that the real-time market presents and make money from that, that will just add to the ability to track capital. So I think that's why we're focused on proper real-time price formation.

Thank you.

MR. HELLRICH-DAWSON: Dr. Bowring, could you explain a little bit the way that PJM at least I guess goes about reducing the volatility as they've said they do?

MR. BOWRING: That's an interesting question. I'm not so sure that's a goal of PJM's. I hope it's not a goal of PJM's to reduce volatility.

I know there's been--

MR. HELLRICH-DAWSON: Well, actually if you disagree, that PJM isn't trying to do that, that's certainly a valid answer.

MR. BOWRING: Oh, I do. I do disagree.

So I mean there are issues about price formation which John has mentioned, and there are legitimate issues about price formation, but price formation can't be perfect in an LMP market where you have other kinds of constraints and thermal constraints. We all understand that.

But as a general matter, I think PJM is not trying to suppress volatility to suppress prices in real-time. I think the discussion about volatility at the seams was an interesting one because it sounds as if people are trying to suppress volatility there and clearly that's not the right goal.

But I think the goal there is to ensure that prices reflect the actual underlying fundamentals. And the real--I mean, my view of the way to think about the optimal solution at the seams is to make it look like an LMP market at the seam.

I mean, we wouldn't control Bennington Black coke using transactions. That would be considered to be backward looking, to say the very least. So the same logic should apply to seams between RTOs and ISOs.

But to address John's points directly, I do not believe that it's PJM's goal or intent to try to suppress volatility in real-time.

MR. HELLRICH-DAWSON: Charlie, let me go back to something you said earlier about demand not being able to respond in the market. Did you mean that to--did you mean that you think demand ought to have a more active participation? Demand ought to be actually a demand curve? Or price responsive demand, or something?

MR. BAYLESS: Well let me start off by saying I agree with what was just said by most everyone here with forward pricing and real-time pricing for 99 percent of market operations. It's only--it's only during those periods of extreme events--really hot days, really cold days--that markets start operating unrationally, and we need these mitigation measures in place.

But as far as your question, it's hard to--we have to operate within the sort of construct that's given to us right now. And under this, retail rates are regulated by states. And, you know, there's nothing we're going to do about that in the short term, or probably any time very soon.

It's--some states are moving towards regulation, or deregulation, and some states I don't see moving towards deregulation any time in the next decade or more.

So we have this regulatory construct. And the way it's set up establishes these price spikes. When you get out to the very right-hand side of the demand curve, you can actually have occurrences when demand exceeds available installed capacity.

In those instances, there's nothing that you can do to incent any more generation to come on line. So I think our point is just we need protections for consumers because of the way the market is established. Or it's not really a market, even, it's just a construct. It's a quasi-market.

MR. QUINN: Charlie, can I ask a follow-up kind of based on what you just said?

MR. BAYLESS: Sure.

MR. QUINN: And something you said earlier about bilateral contracting driving the kind of the building of new capacity?

MR. BAYLESS: Yes.

MR. QUINN: Is there a role, though, for kind of shortage pricing? You know, what I heard is kind of a suggestion that rather than allow kind of administrative pricing to take over when the RTO is experiencing a reserve deficiency, that you'd want to kind of put a fairly hard cap on prices to keep them from going up, because in the short term I think the argument is that demand is not going to be able to respond anyway.

MR. BAYLESS: Right.

MR. QUINN: I think it would be helpful to understand whether, though, those short-term high prices in the real-time market would encourage bilateral contracting to protect you from those short-term price spikes in the real-time, to the extent that you'd be exposed to them.

And if we were to kind of cap those real-time prices, whether we would be disincenting exactly the kind of bilateral contracting I think you've argued would incent, you know, more generation building?

And anyone can, I think can--I'd be happy to have answer this question, as well.

MR. BAYLESS: I'll have to think about that for a second. So the bilateral contracts incent--I'm sorry--

MR. QUINN: I guess my question goes to, you know, I think what I heard was: As a load-serving entity you're just exposed to shortage pricing.

MR. BAYLESS: Right.

MR. QUINN: And that would seem to be true if you didn't take some action like a bilateral contract, you know, maybe with a physical generator, to say I will be covered in all load situations.

So the way that, you know, even if you can't price responsively bid into the real-time market as a load, having some physical hedge would help you kind of avoid those price spikes.

MR. BAYLESS: Okay.

MR. QUINN: And so anything that we did to artificially limit how high prices could get, if we tried to avoid scarcity altogether, or we tried to manage the prices that we got, would lead to less of an incentive for you to want to kind of take on those bilateral contracts to avoid kind of that exposure.

MR. BAYLESS: I supposed you could enter into bilateral contracts to meet 100 percent of your load. But, you know, I think until that point occurs that there's still some--there's still some economic position that you're susceptible to with price spikes.

I mean, if you were completely self-supply, or completely hedged, then you would not be subject--you wouldn't see the price spikes. But until that point, there is some possibility. And I'm not sure that the market is ever going to get to the place where absolutely 100 percent that every single utility out there is completely hedged, has a long-term power purchase contract for 100 percent.

I think that's uneconomical. I mean, you would have to first figure, do you--you know, if you have a peak load of 1000, do you then go in and set up a longer term power purchase contract for 1000 megawatts a day, or 24 hours, you know, 24 x 7 every day of the year, knowing that you're only going to hit that for one day a year?

On the other hand, you may only be using 500 megawatts, or 600 megawatts on a regular daily basis and for some reason you're buying an extra 300 or 400 megawatts that you'll never use just to hedge yourself.

So I don't think load can actually get into the position where they can completely hedge themselves. I think you can enter into some of these long-term contracts to help hedge yourself, but you'll never be completely hedged against market spikes.

And, you know, as long as consumers don't see the price, that's where the spikes really occur. I mean, when you get to these really hot days when demand can actually exceed installed capacity, there's nothing that you can do at that point to incent additional generation.

And, you know, unless you were completely hedged, which is probably an uneconomical operating model for companies, you'll be subject to some sort of market forces then.

MR. BOWRING: Can I just add a couple of simple points there? Is that okay?

MR. HELLRICH-DAWSON: Yes.

MR. BOWRING: So first of all, bilateral contracts reflect market prices. If people except scarcity prices, the bilateral contracts are going to reflect that. So that's a reason to have it.

And of course when supply is less than demand, you're not going to invent generation out of whole cloth on the spot. But again, it's expectations. If prices are higher, generators expect that price to be there, that will, as was said a moment ago, enter into the revenue stream and affect investment decisions.

But fundamentally--and you mentioned this point also--I mean this illustrates the issue with having a demand side of the market. Someone has the incentive to respond here. Someone is out-of-pocket this money, whether it's the ultimate customers or the LSE.

What you want to do is make sure that that, the entity with that incentive has the ability to, as you said exactly correctly, see the price, react to the price, and actually benefit from that reaction.

So whether it's the LSE in this case, or individual customers through various programs, that's an essential part of the market. And the response of demand to price is critical, I agree.

MR. HELLRICH-DAWSON: John?

MR. CITROLO: Thank you. I was going to comment, as well, on the contract issue.

I first want to say, though, in response to

Dr. Bowring, I said if the RTO is focused on price volatility I had a problem. I didn't say they were definitely doing it.

MR. BOWRING: That's my fault.

(Laughter.)

MR. BOWRING: My mistake.

MR. CITROLO: I just wanted to make sure you caught that.

I would separate power purchase agreements into two. One, you have the contract for differences that I'm sure you're all painfully aware of the issues around that, which is tantamount to the traditional regulatory days when we had fuel clauses and those types of things. It's a pass-through.

The other power purchase agreement where you don't have that guarantee, that one probably provides almost a perfect hit, right? I mean, you're going to get back the money.

I don't think there's much liquidity on the buy side right now given where gas prices are going. I mean, last week in Transco Zone Six we saw $1.40 gas. It was actually lower than in the other regions, the first time that's probably happened.

So you went back a couple of years when gas was $5 and $6, someone probably would of said: what, is gas going to be $2 one day? And they were probably reluctant at that time to sign a contract.

So I think with the downward pressure, with the exception of this year, January and February actually spiked LMP in PJM and probably some of the other RTOs, but I just don't think there's that much liquidity on the buy side because no one's going to lock in a loss.

Typically, when we all thought prices, capacity prices and energy prices were going to monotonically increase over time, power purchase agreement for firm power was a great way to hedge that exposure. But that exposure doesn't seem to exist at the same level it did a few years back.

So I'm not sure that a competitive power purchase agreement provides the necessary hedge. That's why once again we're back to the day-ahead market can provide that hedge. And there's other tools. There's over-the-counter tools. You can go on Exchange and buy load in advance, buy power in advance.

We back some of those transactions. The most you see if three-year deals for standard-offer service, and that's probably the extent that the buy side is willing to go at this point.

So like I said, I think there are other hedging tools besides power purchase agreements that are available today for load to, you know, better weather the real-time risk that they have.

Thank you.

MR. CAVICCHI: My comment was similar to John's. I mean, I think there are actually a lot of arrangements that occur in the marketplace. It doesn't--often it's at wholesale. So, you know, we're talking about individual customers.

Sure, there are individual customers in PJM that are big enough and sophisticated enough. Almost all large industrial and commercial customers in PJM mange their own supply. They can respond to prices. Some of them are very sophisticated and can do it in real time and provide spinning reserves.

But even consumers like, you know, any of us who live in a restructured state, our loads are being represented through our wholesale provider who's selling power to the utility. And that entity is taken into account. And it may not be long-enough term perhaps to support an investment, but if the market is sending out the signals, as John was saying, they're probably sufficient.

And I haven't had a chance to review all the APPA stuff, but a lot of plants that get built get hedges. I mean, I think that's common knowledge to most people who are familiar. So it all kind of happens, and it's really just a factor of making sure it's right. And you can get the investment to come forward.

Thanks.

MR. QUINN: I guess just to follow up, so I think in your mind then is shortage pricing an important component of that? Just a tangential secondary component of that entire process? I mean, how does it fit into kind of the level of importance in the--some of the overarching market that drives some of those contracts.

MR. CAVICCHI: I actually think it's important, because I think as Erica was saying, I think our system's underlying generation mixture is changing substantially. It's going to be more and more of an issue--it's already an issue in California, who is working on having--they have a flexible ramp product.

I think that again, having been an engineer in a prior life, not all power points are created equal. They don't all ramp the same way. There's lots of choices you can make when you specify the equipment.

So I think that prices help guide the folks investing on what kind of decisions they want to make. I mean clearly now you see mostly combined cycles in PJM. So it looks good, but, you know, for us like to sit down and understand how they're really going to perform is pretty difficult.

Initially all of the ones built in New England were not built to perform in a load-following fashion. A lot of them went back and redid, they fixed them up with engineering fixes so they could ramp better.

We have to keep in mind, when these things ramp they're very inefficient. So you're going to have tradeoffs. And I think your scarcity pricing works in to giving someone say some comfort: well, if I operate my gas turbine at 70 percent and I take a big hit in my heat rate, you know, I can expect I'm getting that value back somewhere.

Obviously at the time they're trying to get it back from the market. But making the decisions up front to set their plant up to be able to do that I think is what the scarcity pricing helps with.

MR. HELLRICH-DAWSON: So are you kind of agnostic between a ramping product and getting the revenue in shortage pricing?

MR. CAVICCHI: In all honesty, I haven't really thought it through carefully enough, so I haven't followed California's experience and whether a ramping product is what you need. And I was really picking up on the conversation here, which is we're having ramp shortages.

I do think ramp shortages should result in shortage pricing. If that's enough, you know, that may be okay. But I think I would have guessed the experience California has is going to be informative, since they've really encountered the big swings, and maybe to a lesser extent, to access.

Richard before was talking about SPP. So it may become important.

MS. NICHOLSON: To follow up on some topics from the previous panel, you had said, Joe, that not all capacity is created equal. And there was some discussion of subhourly settlement, that some RTOs do it and some don't.

And I believe that greater subhourly settlements would improve some incentives to respond to say scarcity pricing.

Could people who here on the panel who have generation speak to that?

MR. CITROLO: Sure. I'll go. With regard to the price suppression from say self-scheduled units, which we're talking about, let's take an example in PJM right now.

If you have a simple-cycle combustion turbine that clears the day-ahead market, you're not--you don't start that unit until PJM calls you. Sometimes they call you 20 minutes before the operating hour.

So it kind of turns into this game of chicken, of I've already scheduled my gas for the unit. I'm waiting for PJM to call so that I can go ahead and self-schedule. Well if the LMP is high, I'm probably going to go ahead and self-schedule it.

And although I can argue that's a mistake, because now you're suppressing price, if you're bringing on generation that PJM may not necessarily need, or reserves that they don't necessarily need. So you're avoiding--you're helping to avoid perhaps a scarcity event by doing it. And that's the problem we've had on the interchange is, you know, the ace goes up, it lands its way high, they see this price signal since we have--we don't have--we have an hourly integrated price, so they see the first five or six prints of the hour, they can schedule 20 minutes before the interval. They schedule at say 10 after the hour, maybe they saw two prints, they schedule a quarter after the hour, but they get the benefit of the hour and then they get a price of those first five or six high prints, even though when they came on at the bottom of the hour now they're suppressing price. But they take that advantage.

And that's why I think that the ultimate goal, and PJM has taken some steps to correct that, which from our position we support and have supported, and we will support on Thursday--as Adam mentioned, they will be coming before the MRC Commission.

But at the same time I think the ultimate goal is to do things like NYISO and ISO-New England has coming, which is an interval pricing versus the hourly integrated. And I think that will help solve that problem of, we use the term "chasing LMP," and it's some things that, you know, you would say is that people first in the industry, operators who are at the dispatch desk, may not realize, and eventually you learn, but there's still a lot of that going on and it is price suppressive, artificially price suppressive I would say.

MR. HELLRICH-DAWSON: All right.

MS. NICHOLSON: And if you have any comments?

MR. BOWRING: So I mean I thought the conversation this morning about the very short-term scarcity pricing, which I think your question was about, was interesting.

I mean, I think--so there were two ends of the spectrum. I think it is appropriate if it reflects real system conditions along the lines of what Matt White was describing. He was describing a situation where you're really short, you really need it in five minutes, and it's getting you something and is the reason for having the incentive.

On the other hand, I don't think it's appropriate if it's not reflective of real-time system conditions along the line of what Adam was proposing.

So I think PJM needs to be permitted to have shorter term scarcity pricing if it's needed to resolve a real system condition. But the real question, which again was raised this morning and I agree it's the primary concern, is the absence of five-minute pricing.

It's always been the case in PJM that generators learn very quickly they're not to respond to a five- or ten-minute price spike because they know it's going to get averaged out and could well end up being below their actual cost to produce.

So five-minute settlements or a process for paying people on a five-minute basis, as exists for example in the tier one synchronizer reserve response, is a way to deal with that. But moving towards five-minute settlements I think is an important part of that.

Thanks.

MR. HELLRICH-DAWSON: Just going back a little bit with the discussion of the interaction of revenues from the capacity market in pricing energy and ancillary services, Dr. Bowring, since you actually look at the PJM market every year, could you talk just a little bit about sort of what proportion of revenue adequacy comes from, or the revenue comes from each part of that? Could you do that?

MR. BOWRING: Sure. So if I remember the table properly, it's about 75 percent or so of revenues comes from the energy market. And, depending on the year and the prices between, I think it's actually a little bit below 15 percent in 2013 from the capacity markets, I would say between 12 and 20 percent from the capacity market depending on prices. And then the balance from ancillary services.

So the two big pieces are 75 percent and say, on average, 15 percent. Now the 15 percent from the capacity revenues, in my view, reflects prices that have been suppressed compared to where they should have been, and they should have been probably 30 percent higher than that.

So, you know, if you take--so that puts it in the 20 to 25 percent range of where they should be. So scarcity revenues today have not been very significant. One issue is the scarcity pricing is done in PJM is that in my view it's not adequately locational.

And there are clearly measurement problems there. I think there are measurement problems overall with the way in which PJM is triggering scarcity pricing. I think PJM needs to think about how to make it more locational. I think that would provide more granular locational price signals, and also perhaps increase the frequency with which you have scarcity pricing, rather than using DR as a way to get to scarcity pricing without actually doing it.

MR. HELLRICH-DAWSON: That was actually a question I had intended to ask the previous panel--

MR. BOWRING: Oh, I'm sorry.

MR. HELLRICH-DAWSON: --no, no, the previous panel we ran out of time so I didn't get a chance. Did you have more to say about that, the granularity and having the zonal prices?

MR. BOWRING: Yes. I think it should be much more locational than it is in PJM. As Adam indicated, it's really just two areas. It's the Midatlantic area and the entire RTO. But as we saw in ANSI, for example, in the summer of 2013 you can actually have locational blackouts, which must have meant they were short reserves.

The problem is to figure out how to measure it, but I think that challenge can be addressed. So I think the option for much more locational scarcity pricing is one that needs to be perused and developed.

MR. HELLRICH-DAWSON: Any thoughts on that from anybody else? Do you anticipate or can you imagine that actually impacting your revenue streams that significantly?

MR. CITROLO: If we're--I would answer by saying if we are doing things to avoid scarcity events administratively, whether it's buying tier one, or delaying prints of price, just as a couple of examples, if that's what we're doing, then the answer is yes because then there are times where scarcity should have been declared and it wasn't.

It's very--the triggers are very tight as far as we're concerned for scarcity pricing, at least in PJM. It's either we're short reserves or we have a voltage issue. And voltage issues are very subjective. So it's not very transparent to the market.

One of the things--and I think it's the nature of the beast in the capacity market, as Dr. Bowring pointed out, there are some things that we agree with in his State of The Markets Reports that have been price suppressive for capacity revenues.

But you also have the phenomenon similar to self-scheduling and chasing LMP. I'm not sure if there's a capacity trader out there who is going to bid costs maybe $180 a megawatt day let's say in the PJM capacity market, and the market clears at $170. So it seems that the way, you know, we offer into has created people, an incentive to bid to clear rather than to bid to cost.

And that, too, when you see new generation clear at $59 a megawatt day, or $120 a megawatt day, you question bidding behavior. I'm not sure there's anything we can do about that until, you know, perhaps people who are offering resources have learned that, but, you know, it's definitely added to the missing money problem. And like I said, if we are skipping shortage events, that is pinching revenue and pinching recurrence.

So that's something I think we need to look at, is are we administratively avoiding scarcity events?

Thank you.

MS. BOWMAN: I was just going to comment on the locational, the concept of locational scarcity pricing. I think that's actually, if you could define it and quantify it correctly, I think it would be a good asset to have mainly because it would help to show locationally where the need is.

You know, you'll be able to put your asset where you need it and could make improvements at existing assets, whatever it is that's needed you'd be able to see those prices and act accordingly.

So I do think that that, if possible, would be a great idea.

MR. CAVICCHI: And I'd third that. I mean, I think if you can actually get it right, and I think we'll hear from Dr. Patton about that a bit in MISO, and we heard about this morning from NYISO who has had locational operating reserve requirements for quite a long time.

MR. QUINN: So maybe I'll just kind of use a kind of quasi-wrapup of kind of what we've heard so far.

You know, I think we started this process with the desire to just, it's part of a larger price formation discussion. The intent of the staff paper I think was to lay out what we understood to be kind of the mechanics of how it works today, then kind of facilitate some discussion about whether there's anything that we would want to think about changing. Or is there anything we've learned based on experience that suggests that there's best practices, or something that needs to be fixed?

This again goes back to something Bob said earlier, you know, we heard in the capacity market context, if you just fixed energy market pricing, capacity markets would be less important. And so this I guess is part of the, you know, is there something to fix?

And so potentially as kind of a quasi-wrapup question, do you all think there is, that shortage pricing is working about as well as you'd expect something as complicated as shortage pricing to work, can work?

Or is there something obvious to do that would be a priority that you think is kind of clearly we should try to improve it along a certain dimension?

MR. CAVICCHI: I think I have three comments.

It seems that the lack of frequency of shortage pricing means that there's something unusual about it that's not working, just because we've had a lot of hot weather and we've had discussion about maybe it could have worked better.

It seems that the pricing is quite different across all the ISOs, and it would make sense to have some degree of synchronization. Because in a lot of ways it wouldn't seem that it should be so much different between the difference regions.

And I guess the final comment would be that if you're thinking of, you know, fixes, it's more that keeping in mind that it's got to be there, and encouraging it to, you know, perhaps become more consistent and transparent across the different regions.

Because I think a lot of the generation community that now spans a lot of regions would benefit greatly if things are harmonized to some degree.

Thanks.

MS. BOWMAN: Yeah, I guess in terms--I don't know that there's a specific fix that we would propose, but rather just knowing kind of historically the responses to volatility, and as we do to kind of transition and scarcity pricing may become more frequent, maybe the durations are still short. Maybe they're longer, then maybe the prices at which they occur are higher. That just because it's happening doesn't mean that it's a bad thing. It may really be saying, look, we have a need here and this is one way to show that there's a revenue if you're able to solve this need.

So that's the only thing I have to say on that.

MR. CITROLO: Yeah, I'll comment. You may have noticed in my abstract I tried to expand the definition of "shortage pricing," like I said particularly in PJM, because it seems the definition is so tight.

And I would agree with Mr. Cavicchi that the lack of scarcity events over the last 18 months when we first implemented for example in PJM definitely indicates that perhaps we maybe have too tight a triggers.

And I would say, you know, I'm back to preserving the integrity of the two-settlement system. If the real-time market reflects what is on the system and system conditions, then I'm not as concerned about the lack of scarcity events.

When you have, you know, units sitting at min that are being paid Uplift and not in cost, it's very easy for operators to say, I have plenty of reserves. We feel those units should be reflected in price, if that's in fact what those units are being used for, as one example.

So I think once again back to the original question is, yes, if you get the real-time pricing right and the day-ahead pricing obviously goes along with that, then you're less dependent on the capacity revenues, because obviously the revenue will evolve, we calculate the capacity benchmark on net cone, so we would have a lower net cone number, a tighter VR curve in PJM for example capacity market.

So I think it's extremely important that we take a look at the scarcity pricing event triggers, and whether or not we should broaden that to other event hours. Because, like I said, we've had so few, none in 2013, one of the hottest summers in awhile. So I think that's something we need to investigate.

MR. BAYLESS: I think as currently defined, scarcity pricing is working. It's incented--I think it's incented generators over the past few years to perform when needed.

I would add, about making some sort of standardized scarcity pricing approach throughout the RTOs and ISOs, I think scarcity pricing rules are so RTO-specific, they're based on the capacity markets and the market structures, and countless PJM manuals and things like that, that it's very difficult to make sort of a standardized approach across all markets when the rules are so RTO-specific in some of the RTOs, and the way the markets operate.

I'm just not sure that would actually work, to make a standardized approach. But I think that scarcity pricing has served its purpose. I'm not sure that the purpose of scarcity pricing is to occur, you know, more than just a few days a year. I'm not sure it should occur often. So I think it's served its purpose.

MR. BOWRING: So I do think we all need to think about what the definition of "scarcity" is. Because it is somewhat a--it is a choice. Is it 10-minute synchronized reserve? Is it primary reserves? Synchronized or non-synchronized? Is it some longer measure of reserves? I think those are questions that need to be thought about and addressed explicitly with, you know, a clear statement of what the objective is and therefore what the appropriate measurement is.

But more specifically, we need to be able to make sure that the RTOs can actually measure what the level of reserves is from moment to moment. And I think there have been some issues in PJM. I don't know if there have been issued elsewhere, but actually knowing what your reserves are are rather critical to scarcity pricing, and we need to be confident that there really is a real-time measure which is instantaneously accurate, or as close to accurate as possible.

But the flip side of the--or the other side of the definition of it is to make sure that again what was talked about this morning, of making sure that we are reflecting, as it was put, operator actions in scarcity pricing. And by that, very specifically I mean, and both

Matt and Adam talked about it this morning, if the operators decide they actually need more reserves for whatever the reasons are, the legitimate reasons, then that should be reflected in the amount of reserves that are held.

That then affects pricing. It affects the definition of "scarcity." And Matt said it right, which is that if you then increase the amount of reserves, that then defines scarcity. If you're short those reserves which you have increased because the operators need more reserves, that then defines scarcity pricing.

So it's both sides. It's the definition of what you need, and then it's actually defining what you--the actual levels of those reserves you have in real time.

As I indicated, I think scarcity pricing should be more locational. I don't think DR should be used as a proxy for scarcity pricing, as it has been in PJM. I think that PJM should be considering shorter--the ability to implement scarcity pricing for shorter periods, as long as there's a real need for it. And part of that is the five-minute settlement pricing.

And finally, I think we need to think carefully about how the net revenue offset works in the capacity market very carefully with scarcity pricing, because those can be--actually provide perverse incentives. If you have scarcity pricing, it can actually tend to lower the price of capacity exactly when you want it higher.

So the backward-looking method PJM uses pretty clearly is not the right way to go. But exactly what the right way to go still needs to be thought about.

Thank you.

MR. HELLRICH-DAWSON: All right, thank you, everybody.

Before we break here, I wanted to turn to Commissioners Clark and Moeller and see if they had any questions for our panel?

(No response.)

MR. HELLRICH-DAWSON: No? You guys good? Okay, thank you very much. We're going to break for lunch. Now according to our agenda, we will come back together again with panel three at 1:30. Thank you, very much.

(Whereupon, at 12:00 noon, the workshop was recessed, to reconvene at 1:30 p.m., this same day.)

AFTERNOON SESSION

(1:31 p.m.)

MS. NICHOLSON: Hello, everyone. If we could, we'd ask you to take your seats so we can start our third panel this afternoon.

Thank you, and welcome back to our second Price Formation Workshop. We're going to shift focus now and we're going to discuss offer cap mitigation and the energy offer caps.

Just to give a brief overview, this panel we have right now, panel three, is scheduled to go from 1:30 to 3:30 p.m. And then the plan is to have a 15-minute break and resume for the fourth panel from 3:45 to end at 4:45.

I would also like to reiterate and remind everybody that we have noticed some dockets that are before the Commission currently. And even though we did notice these dockets in the September 5th and October 10th notices to address potential, any discussion that might touch on issues raised in those dockets, please refrain from discussing the specifics of those pending cases because we might have to interrupt and we would like to avoid that potential interruptions because we don't want to be rude.

(Laughter.)

MS. NICHOLSON: And we really thank you all very much for your participation. And thanks in advance for working with us on ex parte issues.

We have here Commissioner Bay. I was wondering if you'd like to make any opening remarks?

COMMISSIONER BAY: No.

MS. NICHOLSON: Okay. Thank you. Okay, so with that I think we can start our third panel. And before I introduce the panelists, I'd just like to note that we have here Independent Market Monitors, and we have External Independent Market Monitors for MISO and PJM, and Internal Independent Market Monitors for CAISO, New England, New York, and SPP.

And I'm just going to quickly introduce our panelists. We have Dr. Hildebrandt from California ISO; Dr. Jeffrey McDonald from New England ISO--ISO-New England, excuse me; Shaun Johnson from NYISO; Joe, Dr. Bowring from Monitoring--who monitors PJM; Dr. Catherine Mooney who monitors SPP; and Dr. David Patton who monitors--Potomac Economics--who is Independent Market Monitor for several, and he's here on behalf of MISO.

So jumping into our first question, in the staff paper that we released with respect to this workshop we observed that the average markup over marginal cost estimates for resources at or near the margin was fairly moderate, roughly between 5 and 15 percent, with a significant number of resources either self-scheduling or offering below their reference levels.

First I'd like to ask the Market Monitors in turn if this is consistent with your experience? And if so, do you think that is a result--that this behavior we observed is a result of competitive pressure? Or is it in fact something else? Could it be a bidding behavior that's designed to avoid mitigation?

And as a follow-up to that, is it important why we see this? Do we actually--is it important the reason why we actually would observe seemingly competitive behavior and bidding at the margins?

So we can start the answers here with Dr. Patton for MISO.

MR. PATTON: Yeah, I think we see roughly that sort of behavior in every market that we monitor. And, interestingly, some of the markets are dominated by regulated entities who have different incentives, and some have divested generation that's unregulated and has a more clear profit-maximizing motive.

But in both cases, when you're outside of transmission-constrained areas where you would normally expect the potential for local market power, the offers tend to be very competitive.

And in MISO, the aggregate markup that we've estimated is 1.7 percent in 2013. So it's relatively low.

And even that number, I would say there's a fair amount of uncertainty. We always have to be careful with any markup calculation that are benchmarks that represent short-run marginal costs are subject to significant uncertainty, particularly with regard to difficult-to-estimate issues associated with maintaining units, and wear and tear and risks associated with units.

So in a lot of cases, you know, when we've estimated the offers relative to cost, what we see is that what we think we're concluding is that a pretty significant share of what we would normally refer to as markup is actually probably measurement error, as opposed to an indication of anticompetitive incentives.

So I think, you know, what you found is not--is not at odds with what we see in our markets. And in most cases, in most of the markets we monitor, the mitigation thresholds are, except in very narrow, you know, chronically constrained areas where you'd be greatly concerned about market power, the thresholds are relatively large. And so the theory that they're offering close to their marginal cost to avoid mitigation is actually--you can probably conclude that's not the case because they're not offering close to the top of the threshold.

MS. MOONEY: I just think, no, so the paper didn't look at SPP. Obviously our market is pretty new, but

I would say that it doesn't surprise me, and I think we will probably see some things similar in SPP.

What we have seen so far is that the energy offers are at competitive levels. We do see markups a little higher in our frequently constrained areas, which is--there may be some preliminary evidence that there might be some constraint of the mitigation on offers there, and we don't necessarily have the measurement error issue because our market participants submit the mitigated offers that they're mitigated to as opposed to having the Market Monitor calculating those reference levels.

But it's a little difficult right now in SPP because of an unintended aspect of the system implementation. We have some mitigation occurring that wasn't intended in the design, and it's at a very tight level. It's at a 10 percent threshold.

When the mitigation was designed, it was expected that manual commitments by operators, and anything would be flagged as a manual commitment by an operator, would be a local reliability commitment generally.

And so those resources that are flagged as manual commitments are automatically mitigated at a 10 percent level, and are presumed to have local market power. However, we see that they tend to--the way the system has been designed and implemented, if the operators are staggering commitment schedules, or manually bringing something on say to meet a headroom or a ramping issue, then even if they don't have local market power they're treated as if they do.

And so that's an issue we're dealing with now that's causing most of our mitigation to be not as designed, and therefore we have people responding to that situation and responding to that low 10-percent threshold that wasn't expected.

So that does muddy the waters a little bit in SPP right now.

MR. BOWRING: So as with SPP--oh, I'm sorry. So thank you for the opportunity to be here.

As with SPP, and I think uniquely to PJM and SPP, the members submit cost curves. They submit their own costs. So when you refer to "reference levels," as you make very clear in the paper, in our case it's actually not reference levels calculated by us. And I think there's a lot to be said for having the responsibility for placing offers be the responsibility of the members and not Market Monitors.

An additional introductory point is that in PJM the definition of costs includes a 10 percent adder. The 10 percent adder was designed in prehistoric times--by which I mean before 1999, April 1st as part of the split savings arrangement in PJM, the PJM Power Pool to address uncertainties associated with costs particularly of CTs, particularly associated with ambient air conditions on hot days, generally not intended for other unit types.

And we calculate markup in two different ways. We calculate an average markup for every single unit at various output levels.

And then we deconstruct LMP and calculate the component of LMP that is a result of markup. And in recent years when competitive pressures have been quite high and been relatively low demands, the markup component of LMP has been quite small, less than 5 percent.

I think we would be concerned if that grew to more than 10 percent, but it has not as yet breached that threshold.

I do think that the low markups are generally a result of competitive behavior, not a result of looking at anticipated mitigation. In large part--there are really two reasons.

One is that anyone in a lower pocket would expect to, or is frequently mitigated can put in a price-based offer and a cost-based offer. The price-based offer includes whatever markup they would like. The cost-based offer includes zero markup.

Secondly, and probably more importantly, is we have observed over the years and reported in the State of The Market Report, that coal units who are generally never mitigated, typically offer at less than their defined cost. And that's really a problem with the definition of "cost."

Typically they leave out 10 percent, and typically they leave out certain elements of variable O&M that are permitted in the cost manual but are not truly short-run marginal costs.

So as a result, we see competitive offers by coal units that are competitive because they want to clear, and because PJM has a rule which I think is particularly appropriate for coal units and baseload units, which is you make one offer for the day, which is a strong incentive to bid competitively.

Those units are typically offering at what appears to be, compared to the Manual 115 definition of cost and negative markup, we believe it's really a zero markup.

I don't think the reasons for competitive offers matter. If we have to force people to behave competitively, that's fine. Typically that's not the case. And in fact in PJM, even though there are strong local market power mitigation rules, it really affects a very small number of units and a relatively small number of megawatt hours.

We have in fact seen high markups during high demand periods. And one of the issues in PJM that I don't think is--you may have to interrupt me, I don't think so, but I think it's part of an open docket; yell at me if you have to--is the question of local market power versus aggregate market power.

We have very clear, precise rules for local market power. We really don't have any rules at all for aggregate market power. So if the market is clearing as a whole and conditions are very tight, really it is possible for one or two owners to be singly pivotal or pivotal. And in fact to have markups and to affect the price. And that does occur at times in PJM.

Thanks.

MR. JOHNSON: I'd also like to say thank you for the opportunity to come speak.

Yeah, I would say that in New York I think we find that to be generally consistent, that resources typically are offering near their short-run marginal costs, or are a calculated determination of their short-run marginal costs.

I think, maybe as David pointed out, that some of the ambiguity that we would see there I think tends to be more towards the nature of the calculation of marginal costs, and that there can be temporal disconnects between updates to those costs for resources and the comparison of their actual bid-in data.

So when we are consulting with them after the fact, we often find that there are updates that need to be made to those values that bring the behavior much more in line with what you would expect from competitive entities.

So in general, yeah, I think we would see that competitive expectations, especially in unconstrained zones, is consistent with that. And in constrained zones as well, I think we see resources which are subject to automated mitigation if they should violate those prescribed lower thresholds are relatively consistent with marginal costs.

And I think from what we've seen and heard that our expectation is that that's reasonably associated with competitive forces at play in the marketplace and not necessarily associated with thresholds of mitigation.

MR. McDONALD: Yes, thank you for the opportunity to be here.

I would say from a New England perspective our observation on markups is consistent with what you have in your report. We see low markups. I think we have a healthy level of competition in New England for energy under most load conditions, and certainly under normal gas conditions.

I think to your question of is it strategic, at least seeing low or potentially even negative markups, it might be in some regard. I think because of the high level of competition we do see some suppliers want to come in and be price-takers. And so you'll see lower markups or negative markups as a result of that.

I think also across the large range of loads you'll see a lot of similar heat rate combined cycles providing a fairly flat supply curve. And they're competing with each other in that load range and in that economic clearing range. So I think that type of competition will drive them to a lower, a lower markup in general.

As far as frequency mitigation or observation of potential exercise of market power, we don't see much of that. Like I said earlier, we have I think a fairly healthy degree of competition, and we have very little internal congestion which would create load pockets or local market power that might be more predictable to take advantage of.

So we don't see an awful lot of mitigation, just a healthy amount of competition driving low margins.

MR. HILDEBRANDT: Good afternoon.

Yes, your report also looked at the markups in the California market. And I think our observations are certainly consistent with that.

I would just add, or go into a little more detail. I think what drives the competitive conditions to begin with are a number of factors, starting with the supplies out there. We have a resource adequacy program, so the supply is there.

Most of the load-serving entities in our area are public utilities, and they are encouraged to have really a lot of forward contracting and hedging. So a lot of the capacity--supply of capacity is forward contracted or committed financially.

And then we have strong market power mitigation. So I think those elements--having capacity, having a lot of it under contract, and then having mitigation--they all, it's really a feedback loop.

The mitigation I believe, obviously, even though it's rarely triggered in our markets because of the competitive bidding, it's important because it does encourage the forward contracting at reasonable prices.

So I think those things all fit together in our markets. They result in very competitive bidding, by and large. So I think I would note, we do have a 10 percent adder to the default bids, the reference bids, in our market. And we have strong local market power.

So there can be local market power despite some of the forward contracting. But that is effectively mitigated. And I don't think there--in our market, there really is an incentive to bid above your cost. Actually, when it's competitive you might as well bid your costs, because otherwise you're losing market share.

Our mitigation is very targeted. It only occurs, or it's only triggered when congestion occurs on a noncompetitive constraint. And then it's only applied to units that might relieve that.

So those units, even though that may occur, they don't have an incentive to bid above that. And, unlike--you know, I do think when you have a conduct test where there's a threshold, you know, 50 percent, or $50 above your cost, you know I think that can, before you might get subject to mitigation, that can create an incentive to bid up just below a conduct test. But we really, by skipping that in our market, not having a conduct test, it really removes any incentive to bid just up to that level and avoid mitigation. And instead, it keeps the incentive to be bidding at or near your marginal cost even if you think you might be in a position to exercise local market power.

MS. NICHOLSON: Thank you. That was very helpful.

To follow on to your answer, we actually did in the paper, we summarized two general, main approaches to the market power mitigation, if you will, the conduct and impact approach and a more structural approach.

And if any of you have--Eric, you just were noting that the conduct and impact approach, you were saying, would give resources an incentive to bid just under their cap. So that presumably would be a shortcoming or a weakness of that particular approach.

If anyone who adopts a conduct and impact approach would like to respond, that would be very helpful.

MR. PATTON: Yes, I'd love to respond because we have promoted the conduct and impact approach in almost all the markets that we mitigate, or we monitor. So a couple of things.

That incentive to bid up to your threshold doesn't actually happen. We--we, what we do is we look for withholding at varying levels of offers of anywhere from zero up to the mitigation threshold, and you don't see--we calculate a metric called "the alpha gap." And the alpha gap is essentially a metric that indicates, is there economic capacity based on their benchmark and giving them sort of the threshold level above that, is there economic capacity that looks like it ought to be producing megawatts or ought to be committed? Because we also look at startup costs. and commitment costs as a means of withholding, too.

Is there economic capacity that's not being produced because of the offers of the resources? So what should happen, if that theory were actually correct, is if you look at half of the conduct threshold, all of a sudden you go from nobody is being mitigated to, oh my gosh, now there's 2000 megawatts that look like it's withholding, or it's showing up in the alpha gap. And that really doesn't happen. The alpha gap is very small at almost all levels of thresholds that you would use.

But I think, rather than casting it as an alternative, because I think we all have elements of structural tests, and we all have elements of conduct and impact, that you could argue that California is applying a conduct test at zero. You could argue that PJM is applying a conduct test at 10 percent with an impact test of zero.

So it's easier to think about the contrast in these I think by saying, well, everybody is applying some version of this, but some of our thresholds are effectively zero. So we don't require an impact.

And in MISO, for example, the areas that are mitigated and the level of the threshold is based on structural tests. So we only mitigate in constrained areas, and we perform pivotal supplier tests to evaluate the level of market power in those areas. And that contributes to what thresholds are applied.

So there's always a structural element, because you only ever want to mitigate market power. But the value of the impact test, we mitigate something like 1 to 2 percent of the hours in MISO in broad constrained areas, and 1 to 2 percent in narrow constrained areas. Notwithstanding the fact that these constraints are binding a lot. MISO is one of the most congested areas in the country and has, you know, a billion and a half dollars of congestion a year.

So there's lots of constrained areas, and you would think you would be mitigating a lot. But the value of the impact test is we require that there be a demonstration that somebody actually has market power before we mitigate them.

And if the definition of "market power" is the supplier has the ability to raise prices, I want to see that they're raising prices before I intervene, or before the RTO intervenes and caps their offer.

So what it does is it greatly scopes down the frequency with which you mitigate. And what you end up not mitigating is extremely low impact behavior that's not costing consumers very much money, but the value of not intervening is that if these are resources that actually have legitimate costs, it's very expensive to tell them to run when they're not the marginal resource.

So if they have some legitimate costs that are not affecting prices and you lower their offer and that causes them to dispatch up to their maximum, and therefore there's some other cheap unit in the load pocket that could have resolved the constraint but yet you're making this guy run, that's a cost that ultimately is going to be borne by consumers because that's a cost that supplier is incurring and ultimately that doesn't stay with that supplier but it works into the risk that they see of operating in that market and so forth.

So it's very--I think it's valuable to design mechanisms to limit the mitigation to only those cases where you really believe there's an exercise of market power happening.

MR. BOWRING: I would agree with the last statement, but not much of what preceded it.

(Laughter.)

MR. BOWRING: So I mean we do have a structural market power test and three pivotal supplier tests, which is applied dynamically in both the day-ahead and real-time markets as the market clears.

So whenever a constraint is binding, the test is run. I think a impact and impact test of zero is appropriate. I think--I mean, I agree with David that the way to think about it is in a sense a raw conduct and impact test. But I've said that for a long time. I think it makes sense to think of it that way, and I would agree that we have, for better or worse, a 10 percent adder to cost, and then a zero impact test.

I don't think any of the secondary effects actually occur, and in fact using the approach we use in PJM, as I indicated a moment ago, mitigation does not occur very frequently. It tends to be focused on a relatively small number of units that are in very tight load pockets with a small number of owners for historical reasons.

Thanks.

MR. QUINN: Joe, could I just follow up real quick? Do you think part of your view is because the resources themselves are submitting their costs to you? I mean, part of what I heard David describe was fear that the measurement of that marginal cost, that reference level, wasn't going to be very precise.

MR. BOWRING: I think that's a great point. So, yes, so we're not--they submit their costs. I mean, they have to follow rules about it, but if they think they have an opportunity cost, for example, we have a sophisticated way of calculating opportunity cost. They're using it more frequently these days. And if they believe that there are costs that aren't being captured, they have the ability to tell us that.

But, yes, I do agree it's critical that the units themselves, the owners themselves, provide the costs. And there can be no question about whether they're the right level of costs. It's not us guessing at it. It's them telling us what the costs are.

MS. MOONEY: I just wanted to add, in SPP we do see in the conduct and impact environment generators bidding up to, trying to avoid some mitigation, as I mentioned before.

On the energy side, I thought it was interesting that the study focused on energy. On energy, we don't see a lot of mitigation because there's not much markup, but also the impact test does eliminate a fair amount of that mitigation.

What we do see is a startup mitigation, startup costs. Because we are, in our unit commitment processes automatically looking at startup cost mitigation every day, at a 25 percent conduct threshold and a $15 per megawatt hour, you know, for looking at--so we'll look at a potential make-whole payment for a commitment period, which is usually a day, say in the day-ahead market, and look at how many megawatt hours is that resource running? And how much does the mitigation affect their make-whole payment per megawatt hour that they're going to run?

And we do see that those failed the conduct and impact test.

MR. McDONALD: I'll follow up on what Catherine said with a comparison to New England. I mentioned earlier that we see very infrequent mitigation of energy bid curve, but as with SPP we do see the bulk of our mitigation occur for commitment costs with startup and no-load costs.

And that arises I think because we have areas where we've got reliability considerations where you see manual unit commitment or uneconomic unit commitments made by the operators. And we've got rules because of the uniquely situated nature of those resources where mitigation will kick in. And that's where the bulk of our mitigation shows up.

MR. HILDEBRANDT: And just to I guess address whether, you know, alternative approaches result in a lot of mitigation or not, you know, we do, I guess--every year we look at this. And, you know, I did--I have some numbers from our last annual report on the mitigation section. And in our day-ahead market there are 16 unit hours that are subject to mitigation, meaning, you know, they can help relieve congestion on a constraint, or a congestion has occurred and it's been deemed noncompetitive.

But in the end, only .5 units actually have their bid changed. And I think that's an indicator of, well, first of all, we do have a maybe somewhat unique in that we don't lower bids unless the bid is lower than what we call the competitive locational marginal price.

And that's based on the market-clearing price based on bids, unmitigated bids, that's run before the market but it includes the system marginal energy cost, and congestion and competitive constraints.

So if overall prices are high, if gas is high, other conditions are driving prices higher, that serves as a floor and we don't mitigate bids even if they're subject to mitigation below that.

The other key factor is, many units bid at or below their default energy bid, which includes the 10 percent adder. So when you look at those two things, you know, in the end we're only changing the bid of .5 units per hour in the day-ahead. In the real-time it's slightly higher, one unit per hour actually has their bid changed.

And then the impact of that is very low. Again, in the day-ahead during peak hours we've calculated it's about an extra 15 megawatt hours during peak hours that gets dispatched from units that have their bid lower. And in real-time about 25 megawatts per hour.

So again, it's very infrequent and very targeted when our mitigation does have the effect. And I think again it's because of these other people that are bidding at or near their costs to begin with. And we do have this provision, so if market prices are higher due to other conditions, that serves as a floor in our bid mitigation process.

MR. JOHNSON: Just maybe a quick follow up. In New York we do very much operate under the conduct and impact scenario, and we have a variety of zero and non-zero conduct and impact screens, depending on the type of mitigation.

And I think--and David was alluding to this earlier--this notion that when you have a conduct screen to monitor at lower thresholds, and so we're actually obligated in our Tariffs to, not only to monitor but if behavior is found to then bring it forward and recommend additional mitigation measures. And we've done that once before.

And so I think having the transparency of that provision available to stakeholders adds some credence on their part of not do the--to bid up to the conduct thresholds as that concept that something else could occur if you didn't.

MS. NICHOLSON: Thank you. Do we have any other comments on the last line of questions?

(No response.)

MS. NICHOLSON: Okay, I just wanted to switch gears slightly to discuss in more detail the marginal cost estimates that largely underlie mitigation in the markets. As we have discussed earlier, they are submitted by the market participants themselves in SPP and PJM, and that compares to them being calculated by the Market Monitors in California, New England, NYISO, and in MISO.

I was wondering if we could go, if I could ask you to speak in turn about a brief synopsis of the reference level estimates in your market, and whether they in your opinion adequately reflect the short-run marginal costs of the resources that you're trying to estimate for and included in short-run marginal costs. If you could comment about opportunity costs, and if they're sufficiently included in your opinion?

And I think we can start with Catherine, so we don't keep hitting you first, David. And I'll go down the line, to be fair. So, Catherine, from SPP.

MS. MOONEY: Sure. No problem.

And thank you for raising this question in this forum. In SPP we have a specific tariff provision that requires market participants to submit their short-run marginal costs, exclusive of fixed costs.

And for the Market Monitor to verify the accuracy of those short-run marginal costs and the consistency of the application of that standard across market participants, which is an important part of that.

In implementing this process, we've discovered a what I would think of as a misunderstanding, or at least a disagreement between the Market Monitor and many of the market participants as to what their short-run marginal costs are.

And we also have learned that there's inconsistencies in this across the RTOs which has led to some of the ambiguity in how we implement this process.

You know, to get to the specific question, are all resource supply costs adequately included in short-run marginal costs? It's important to keep in mind that there are many legitimate costs that should not be included as short-run marginal costs. And that's an important part of this discussion.

Some short-run marginal costs are very tangible and easy to quantify, like fuel costs. Others are intangible like opportunity costs.

And I think it's important with the intangible costs that the Market Monitor play a proactive role in the development of these, and I think that's generally done.

In SPP we have a very detailed process for developing opportunity cost calculations which we're using for environmentally limited resources, and fuel-limited resources. And so, yes, I do feel that we've sufficiently accounted for opportunity costs in our mitigated offer approach.

Where we've run into a lot of the disagreement is really around maintenance costs. And what is a short-run marginal maintenance cost? And I really think this comes down to two specific issues.

The first issue is the historic regulatory based variable operations and maintenance standards, such as those that are developed from FERC accounting. They're not based on competitive market economics. And they include fixed costs, and they can in some cases vastly overstate the short-run marginal costs for maintenance, especially for infrequently run units.

So we have seen infrequently run units that have calculated a variable operations and maintenance cost off of FERC accounting that would exceed the $1000 offer cap for energy. So we do see, you know, these calculations can lead to unreasonable numbers.

And SPP is dominated by vertically integrated utilities and cooperatives and public power entities, and they seem to have this strong incentive to have the costs that they will get in their make-whole payments to match up with what they have as variable costs in their rate base with the states.

And the issues that this leads to is, you know, most of these costs are going to match up, but there are some inconsistencies. And what's included, you know, in their variable costs in their rate bases isn't necessarily based on competitive market economics.

And the standards can vary from state to state. So when we're dealing with, you know, many, many states in SPP, we do see these discrepancies. And because we are charged with a consistent standard across market participants, and they're asking for a different standards basically across market participants in some cases.

The second issue is the determination of where to draw the line between a short-run maintenance cost and a long-run maintenance cost, particularly with regards to major maintenance or overhauls.

And the difficulty here is that if these expenses are only incurred say once every five years, and there's really no perceivable consumption of a production input, you know, with regards to this type of maintenance, is it a short-run marginal cost?

And does having it written up in a contract on a per-start, per-hour, per-megawatt hour basis, make it a short-run marginal cost? And the SPP Market Monitoring Unit has not been convinced that this is the case, although we've heard a lot of argument from both sides, had a lot of conversations about this.

The big concern that I have with the contract costs is that I don't feel like as a Market Monitor we want to be in the business of driving people's decisions about these types of contracts, but somebody comes to us and we look at their cost data and they explain to us the situation they're in, which is, you know, one thing that we like about having them have that control over their costs, although I know even with the reference level approach there's some of that as well, we're in a situation where if, based on short-run marginal costs they have a start-up offer for a combustion turbine that would be $1000. But they have a contract that says they have to pay another $15,000 every time they start.

Now if we say, okay, if you have the contract you can use $15,000 in your start-up offer, but if you don't have the contract for an identical resource you're at $1,000, that creates an incentive for them to go get a contract that would otherwise be--they've already previously determined was uneconomic and not worth the investment.

So we don't want to be in a position of driving those decisions, and that's difficult.

So those are the two big things that have come up I think that drive the question about what's a short-run marginal maintenance cost in SPP? And that, I don't think, is a unique issue to SPP. I think that every market has, you know, some of these questions come up from time to time.

And I expect the Commission will be receiving tariff changes from SPP at some point to clarify some of these issues, and the Market Monitoring Unit hopes that that process will be driven by competitive market economics as opposed to really the historic operating practices of generators, many of whom have market power.

MS. NICHOLSON: Thank you. I do believe you colleague from SPP has raised his tent. Can you turn [the microphone] on? Do you know how to operate that?

MR. DILLON: Hopefully so. Can you hear me? As Catherine aptly pointed out, we have recently implemented a new process. And we have slammed full-bore into the reason that utilities are monopolies and have to have mitigated rules that some costs are not totally accountable on a per-unit basis. It's not widgets that are being made.

And, you know, we are struggling through the application of a free and flowing market concept based on widgets that says short-run marginal costs are supposed to be composed of certain items.

And so we are full-bore running into a free economic concept being applied to a monopoly environment that's a monopoly for a reason. And that not all costs can be readily attributable. And in that manner, as we get terms like short-run marginal costs thrown in that historically was not part of a utility concept, many of us are left to try to figure out how that is defined.

And that is creating concerns. We have short-run marginal costs. You know, everyone's back and forth. I don't know what the true costs are. But when I see a generator with a $4 start-up cost, four dollars, not four dollars per megawatt, $4, I have to wonder if the participant has the calculation right; if we have the rules right.

And it's something that we need to be very careful of. As Catherine pointed out, we have historical utility accounting practices that are not aligned with the environment we're in right now.

By the same token, a free-flowing market is not aligned with the delivery of electricity in monopoly. There is somewhere in between, and we're struggling at SPP with that collision at the moment.

MS. NICHOLSON: Thank you for that. I believe, Catherine?

MS. MOONEY: May I respond to the $4 start-up offer.

(Laughter.)

MS. MOONEY: So let me explain how a resource would end up with a $4 start-up, mitigated start-up offer in SPP. So I believe what Richard's referring to would be a gas-fired generator. And there are--you know, we have in our Tariff spelled out very specific formulas for how to calculate a mitigated startup offer.

So--and keep in mind, the market participant does submit this themselves, and it is on them to do the calculations correctly, right? And we have the underlying data reported to us so that we can check to see if they're doing it correctly.

So a $4 mitigated startup offer would mean they felt that it only required 1 MMBtu of fuel to start. And this could be possible for very new, fast-ramping resource potentially, or a quick start. It's possible, but I haven't seen this. Actually, I haven't seen a report of a $1 per MMBtu startup offer.

So on top of that, they would have to, you know, be saying that they don't have any additional labor costs for starting. They don't have any additional maintenance costs for starting. And all of those items are determined by the market participant. And if they don't claim to have any of those costs, then, yes, they would be required to put in a $4 startup offer based on $4 gas and only 1 MMBtu of fuel to start.

So that's where it comes from. But it is on the market participants to do this correctly. And then it's another question when we see possibly in the data some numbers like that if the market participant has made the correct calculation.

MS. NICHOLSON: Thank you.

MR. BOWRING: So Catherine is certainly right that other RTOs face similar issues. It's interesting to hear about SPP's issues as they begin, because they remind me a great deal of the issues that we faced when we began. And unfortunately for Catherine, we're still facing them, although --

(Laughter.)

MR. BOWRING: --to a lesser extent.

So as I indicated earlier, we inherited the system. The Cost Development Manual--I think the first Cost Development Task Force meeting I went to, on the header of every meeting agenda it says what number meeting it was, and I think it was probably meeting number 289 was the first one I went to, and that was the first meeting under the market. So there were obviously a lot of meetings pre-market.

And it was all about split savings. There were different sets of incentives. It was, as Richard said, utility accounting not market accounting. And I disagree with him that it's hard to make that transition. It's not that hard at all. But you do have to make that transition. And there's a greta deal of resistance to it, which I really think the point is.

There's a lot of utility thinking, and a lot of that still persists even in our market. But one of the things we realized in thinking about what the correct definition of short-run marginal cost is and whether, for example, it includes your average overhaul cost for the last 30 years which is in fact what was included initially in the Manual when we first started up, 30 years of overhaul costs upgraded with a handy Whitman Index guaranteed to get you a meaningless number.

(Laughter.)

MR. BOWRING: And I believe it did. I mean, we pointed out that overhauls were not short-run marginal costs. They're clearly not short-run marginal costs and neither are inspections. But really what the fundamental issue turned out to be at kind of the gut level was it was about revenues. It was not about costs.

If they could divorce short-run marginal costs entirely from revenues, there never would have been a discussion about it. Everyone would have agreed on what short-run marginal costs were, right? I think people really do recognize it.

I've had lots of conversations with participants, owners of coal units for example who at one point argued that they needed $20 to $30 in variable O&M, who once they became competitive with gas, took all that out and admitted very freely this was a competitive offer.

So there's that history. Now we--and the reason revenues are an issue is because when you're frequently mitigated and if you're always marginal, it means you are going to receive an incentive to go out of business. Which is why--and, you know, that's actually a fact, which is why we introduced FMUs, and why we went through that history, and why we ultimately have a capacity market.

So there are other revenue-related issues. But they're really not about the definition of short-run marginal costs. The definition of short-run marginal costs is not that hard. The reason it's so emotionally fraught is because there are other things that get attached to it both in our market and in other markets.

You did ask a question about opportunity costs. We do a calculation of opportunity costs looking at forward prices for power and gas, calculating what the most profitable hours would be in the future, and using those hours to calculate an opportunity cost for the current time period.

Now we think it's critical that limited units, as they're defined in PJM including environmentally limited units, have the opportunity to offer opportunity costs. Those are clearly part of short-run marginal costs.

I've had people tell me for 15 years that they really want to add a risk premium to that day-ahead offer because there's really risks there. You know, they might not run in real-time. And I've asked every one of them to come back to me and explain to me how they would like to calculate it, and I have yet to have anybody come back and explain how they would calculate it. I have yet to have anyone actually add it because it's actually not a part of the competitive offer. You won't clear if you add a risk premium.

I mean, there are lots of things that people would like to add to their offer as cost-based offers day-ahead, but typically, as I said, it's about revenue not about marginal costs.

And one last point on contracts. I mean, I agree with what Catherine said about contracts. We face exactly that same issue. And in fact, if you let people define anything that's in a contract as short-run marginal costs, they have an incentive to not only enter into contracts with the OEMs but incentives to offer to enter into contracts with themselves, with their own affiliates. And we saw people beginning to think that way as that issue was discussed.

So the contracting issue is a very slippery slope. And even though it's tempting to think that because it's incremental in a sense, actually you incur that cost under contract, that does not make it a short-run marginal cost.

Thanks.

MR. JOHNSON: So in New York, you know I think in general most of the references are short-run marginal costs that we used in our determinations are submitted one way or the other via the entities. We have a hierarchy of determination of marginal costs in New York, and the primary methodology described in the Tariff has been based. And then there are cost metrics that are also proposed by the entity. And finally, as sort of a fallback, there's an ISO-determined methodology.

So most of that does come from market participants into our software. And that includes calculations from opportunity cost to risk premiums, as well as consultations on those requests.

One of the ways that I think we've certainly enhanced that capability in the last few years is when we moved to the functionality in New York to allow resources to increase their real-time offers from their accepted day-ahead schedules, we do that in conjunction with allowing them to adjust their reference costs in real-time.

So our short-run marginal costs are fuel-indiced and that's only as accurate as the fuel indexes are, right? And when you get into volatile fuel periods, those indices tend to have a wide bid/ask spread. So depending on where resources fall into that, they will submit their corresponding fuel adjustments for that day into those costs, which at least in our--in New York we feel allows them to have a better, more accurate representation of those costs in the market and how the costs are running. You know, there is verification in place associated with that and potential penalties for misuse of that feature, but it has been fairly successful in the few years we've had it in implementation.

So from that perspective, I think we've had fairly well success, especially recently since that functionality has been added, of our ability to reflect these costs into the marketplace. Obviously, as I think everyone else is alluding to, there's always going to be disagreements on what a cost is and how you do a calculation.

But in general I think there's--there's been increasing conformity in New York as to how that calculation works across the spectrum.

MR. McDONALD: In New England we do have a marginal cost option for the reference curve, and it's by far the most commonly used of the options.

I think that from what I've heard so far I can say that we incorporate most of the--what this panel might almost agree are variable costs, you know, for generating resource.

We do incorporate energy opportunity cost as well, if requested. We don't have a sophisticated model for doing that. We actually work with the market participant. If they've got a model that they use they can present that to us, so it's dealt with in more of a consultative fashion on a participant-by-participant basis.

That's not very common, actually, in our market. So we don't see an awful lot of that. We do have in terms of their reference--cost-based reference curves being able to reflect changes in their costs, we currently have a single bid curve for the whole day for the day-ahead market as well as for the real-time market. So they can be different bid curves, but they're in effect for each of the 24 hours.

We're moving, in December we're moving to an hourly offer construct. And along with that, we will be facilitating up to hourly changes in other expected fuel prices which we're hoping will help more accurately reflect their underlying costs as we go through another winter likely like the last where you have a lot of high fuel volatility.

MR. HILDEBRANDT: So I think the original question, yes, I think we feel pretty confident that the reference bids in our market reflect the true marginal costs.

I think it's a bit of a misnomer to say the ISO calculates these in our market. Actually the participant selects. There's a cost-based option, or we call it a negotiated option. Again, the participant can propose, you know, a cost. It could be a special opportunity cost associated with, you know, if they have a fuel limit of some kind, or a hydro unit--it's fairly common to have that. So any other customized cost can be incorporated in that, and it's worked out with the ISO.

So I think the big difference is they are determined before the fact, and they're not subject--they're determined before the fact. It's an agreed formula calculation before the fact. It's not subject to the operator trying to approve it minutes before the market between the time it's submitted and the market runs. I don't think there's enough time to do any kind of verification there.

And it's not subjected to some kind of an ex poste review. I think we view that as problematic for a variety of reasons. You know, one of course is the market has already run. So the bid has either not been accepted and affected the market price that way, or it's been accepted and potentially just affected the market price that way.

So I think we see the after-the-fact verification as problematic, and we really view it more as agreeing with the participant up front on whatever the approach is, and it can incorporate really anything as long as it is a marginal cost, including opportunity cost, for the unit.

MS. NICHOLSON: Thank you. David, from MISO?

MR. PATTON: It's a luxury to be going after Joe.

One thing I want to stress, and I think it's very important to understand this, is this is a false dichotomy, this notion of submitted versus calculated.

There's no difference between any of us, no meaningful difference that is. All of the cost-based reference levels is based on information being submitted by the market participant. So I can tell a market participant on a daily basis please tell me what your cost is? And they may say $50. Alternatively, I can tell them: Tell me what your heat rate is and where you buy your gas? And I'll use that index. And if it's wrong, then tell me on a daily basis how much you're paying for gas and I'll calculate that. I'll multiply the heat rate times that and I'll have a cost-based offer.

I think the only difference between those two scenarios is I'm getting a lot more information if I ask them for the inputs to the cost, rather than just asking them for the final cost. That's extremely valuable, and I think actually the--I'm pretty certain that the folks who are getting a cost-based offer are also getting inputs.

Otherwise, there would be no way to validate that the costs are remotely correct. But by getting that detailed information, it facilitates the validation because you can compare the inputs that you're getting for very similar units and identify any outlyers that may represent information that's less than truthful.

So in all of our cases I think what we're relying on is cost information being provided by participants, and we're engaging in activities to validate those costs.

I think the one meaningful difference between some of these markets is whether that is the only benchmark, or whether there are alternative benchmarks. And one of the benchmarks that is applied in some of these markets is sort of a revealed preference benchmark which says if you're not in a constrained area, if you're in a location where it's unlikely you have market power, then we're going to look at your typical offer over the past 90 days and fuel adjust that based on the fuel price changes.

And what you find out, that does a couple of things for you. It gives you really valuable information for validating the cost information they give you, because when you subject them to market discipline they have a hard time arguing against what they themselves do when you question their costs.

But secondly, this validation process is extremely resource intensive. I mean, if you're talking about MISO with 1,200 units, I mean you just can't focus on the inputs for every unit. And what this does is it gives you good information on a very large quantity of units.

Now we know those units that are in load pockets where they may significantly affect price. We also know the units that are getting a lot of make-whole payments where their incentive is to--they don't have the typical bid-your shortrun marginal costs incentives. They have pay-as-offer incentives.

So we can dig in far deeper on theirs because we know these are the entities that likely have market power, but the bid-based benchmark is, you know, great from the perspective of economizing our resources.

And we've done a variety of studies on those bid-based references. They tend to be less than the cost-based which is an interest--it actually doesn't surprise me, because anyone submitting their costs is going to have an incentive to represent costs that are as high as they can attempt to justify.

Now with regard to short-run marginal costs and what is a short-run marginal cost, and so forth, I think what we always try to do is say: If I own this unit, and this is the only unit I owned, and I was sitting in an area where it's not affected by congestion, would I have the incentive to represent this in my cost? Does this make sense or not?

And it's like--I'm not sure the time periodicity even really matters that much. So you have a car and you may say it cost me 20 cents a mile in gas to go somewhere, and you're considering driving your car to Florida or taking a plane.

Well, I think we all recognize it doesn't cost us 20 cents a mile, because, you know, our tires have to be replaced every 20,000 miles, and there's some probability we'll lose our transmission, and so forth. So it's actually 40 cents a mile to go to Florida. And maybe I'm more rational than the average decisionmaker, but I factor those things in. And it's like if you own a power plant and you know that every time you start it there's a probability of having a catastrophic failure, that matters a lot if my unit cost $50 and the prices are, you know, am I going to start it to make $51 when I'm incurring that risk? And I'm one start closer to having to do an overhaul, for example?

Those are costs that are material. But in order to evaluate those, I think it is important to have solid engineering expertise that you can rely on to evaluate the maintenance cycles that people are claiming. Because for the most common resource types, the maintenance cycles are not a mystery.

Often the manufacturers publish the suggested maintenance. And so whether it's per-start, or per-megawatt-hour, you know, those are things that when we've gone through the exercise of calculating and incorporating those, we don't find that they're outlandish.

I think a participant sometimes will tell you things that are outlandish, but I think, you know, if you apply your resources then you can get down to the truth. And my feeling is it's important not to ignore those.

Finally, with regard to opportunity costs, this is another area where I think it's very important to get clear, accurate information on what the temporal limitation is. Because if you force the participants to give you the information on what the source of the opportunity cost is, it's typically not that hard to write an algorithm that would calculate the value of that opportunity cost and to use that to validate.

But again here's another area where the bid-based reference levels are really important, or really valuable, because they will represent those opportunity costs in their offers when they're facing competition.

So it gets you pretty far down the road of being able to accurately evaluate the opportunity costs. And with the augmentation of the information they give you, you do have the ability to validate those sorts of costs.

MS. NICHOLSON: Thank you. Do we have any further comments?

MR. BOWRING: Just a couple of minor comments.

So I think that, I mean I understand what David is saying about the information. I'm sure that those who are not--who are calculating the offers, or however you want to put it, are. So they're not simply taking the offers from participants.

I'm sure that there's a lot of information, and I'm sure everyone's confident those are actually the right offers, but what's critical to us is that the participants have the final responsibility and the only responsibility for putting an offer into the system.

We don't want that responsibility, nor should we have it. We don't want to be liable for that, nor should we be. It is the participant's decision and only the participant's decision. That's one of the bedrocks of the way that at least PJM market functions, was one of the first things taught to be when I got to PJM, and I think it's a critical philosophical piece of the way it works, quite apart from the details of any calculation.

I would say in response to David's car example that, yeah, those are real costs; they're just not short-run marginal costs. And in fact, the way we see real units actually offer in PJM is true short-run marginal costs, not the cost of the tires, not the cost of the overhauls, and not the 10 percent, true short-run marginal costs. In the case of a coal unit, fuel times the heat rate, emissions costs, reagents, not much more than that.

And that's the way we see real units being offered competitively. So again it's not about whether costs are legitimate. I'm sure all the costs are legitimate. It's where the appropriate place to recover them in the markets really is.

Thanks.

MS. NICHOLSON: All right. Catherine? Thank you.

MS. MOONEY: Yes, thanks. A couple of these--a lot of the things David mentioned are things that we are working on and have tried to do in SPP. And I think some of our concern with, especially for the combined cycles and the combustion turbines, looking at competitive incentives, is that the incentives that they're seeing in the market--and a lot of this is just based on our fuel mix and, you know, just where relative prices for coal and gas are and those types of things.

But the gas is running very frequently for make-whole payments. And so that competitive incentive to run for an LMP that's above your costs may be lacking. And so that's a concern if you have, you know, a lot of your marginal resources frequently receiving make-whole payments, not because there's a local issue but kind of at a marketwide level that could be doing on.

And I'm not saying that they all are getting make-whole payments every time they're turned on or anything, but it is frequent and it's what's driving our conversations. People are asking, you know, they're talking about getting these costs in their make-whole payments. And we're not focusing the conversation around having, you know, good price signals and having LMPs that reflect market economics that would drive the right incentives for offers.

And that's, you know, one thing that makes the conversation very difficult.

And another thing that makes it difficult in dealing with market participants about these costs is it's not always clear that the information that they have--especially if they're not the ones who perform the maintenance on their resources--tells them which costs, you know, from an engineering standpoint are the maintenance costs, and which costs are, you know, customer service costs or something that's more like a warranty from, you know, the manufacturer of the unit.

And so some of that complicates it and makes it difficult to work through with the market participant when they don't actually see that breakdown themselves because they don't perform their own maintenance.

Thanks.

MS. NICHOLSON: All right. I think it would be--we can move on to the next topic. With a bunch of economists we could talk about short-run/long-run all day.

So we'll move on. Thank you very much for your insights there.

My next question relates to the flexibility inherent in the rules in your market, and whether they are sufficiently flexible to allow resources to fully reflect their supply costs in their offers.

And in particular, whether if the offer rules are flexible enough to allow them to reflect costs between the day-ahead and real-time, and across hours in real-time.

And I believe, Joe, you were next in line in my system here.

MR. BOWRING: What is it? It's an hour, or to go in front of David--

(Laughter.)

MR. BOWRING: I love to go in front of David. So I think we may have come close to agreement on this.

So one of the issues we saw years ago, seven or eight years ago, the last time gas prices were actually high in PJM, was the issue about rebidding. And although I indicated a few minutes ago that I think it's a critical market power rule that everyone have one offer per day, it's also critical that units that are not taken have the ability to rebid in real-time.

Now I don't think that's actually necessary for coal units or nuclear power plants. It is necessary for gas-fired units. PJM has had a very primitive rule in place for a number of years which permits units, if you burn through your minimum run time and you need to switch to gas contracts or to another fuel, you actually can switch. You can actually switch schedules.

So as I said, that's primitive. PJM is working on it, and we are working on a better way to do that to implement as soon as possible, particularly in light of what happened last winter.

But it is important to allow that. But I mean you have to think that through very carefully. It's a complex--it's a complex set of issues about ensuring that day-ahead, binding day-ahead offers and commitments are still honored, and that you deal with Uplift questions and you deal with market power questions.

But as a general matter, it does make sense to be able to reflect the real-time costs of fuel if you were not committed day-ahead in real-time. It's actually essential to making the market actually work well.

So I mean I think that's the primary area where the PJM rules are now not adequately flexible and need to be more flexible, but that's actually in process. So I think that's a very good thing.

Thanks.

MR. JOHNSON: So I think I alluded to this a little bit in my last comments, but we moved a few years ago to this increasing bids in real-time functionality which does allow resources to reoffer in on an hourly basis, even they're day-ahead scheduled.

It is important to note the one thing that they cannot do is remove the commitment from an economic purpose, obviously, if the unit is not physically capable to run they're commitment's no longer viable. But so this would be changes in their offers above their minimum generation commitment level.

We did that for a variety of reasons, but really it boils down to from our perspective sort of a fundamental market perspective, that we want--it's imperative for us that our real-time market actually reflect the true cost of operating the system and solving to meet our loads.

And ultimately it is less expensive to have a resource that was scheduled day-ahead buy out of that position and have a lower cost resource run that's the correct economic solution.

Now it is important, and I think this is what Dr. Bowring was alluding to, is this idea of you need to have the correct safeguards in place. Right? So that a significant part of that was working through the measures and safeguards in place, and removing some potential problems that could arise either from deeming of guaranteed payments or portfolio perspectives, and how you manage that. So that needs to go hand in hand with appropriate safeguards.

But allowing that flexibility of resources was a fairly large achievement in New York several years ago and we correspondingly made the change to allow references to reflect that as well. And it really does provide a truer, accurate signal for us in real-time that by and large our community in New York has been fairly happy with, and I think has provided some interesting case studies for other ISOs to look at.

MR. McDONALD: So I think I had alluded earlier that we were, in New England, moving to a much more flexible bidding structure, so I won't cover that part of it again. But I will--I will agree with some comments that were made just a couple of moments ago regarding some of the pitfalls of too much flexibility in the bidding structure.

You know, provided that it's used in the nature of most accurately reflecting changes in your costs as you move from day-ahead to real-time market, or as your costs--you may face different fuel-input costs throughout the day and not just a flat fuel cost throughout the day, I think that's perfectly appropriate.

I know there have been instances that have been before the Commission having to do with over-leveraging of bidding flexibility to maximize make-whole payments. There's a temporal market power aspect to moving from the day-ahead to the real-time market where all of a sudden a lot of your longer-start units are no longer available to you, and so you're dealing with a different pool of competition.

So I think those things need to be considered, along with the flexibility that we're providing suppliers to more accurately reflect their fuel input costs by giving them that flexibility.

MR. HILDEBRANDT: Actually, I think there's a slight distinction here that may have been missed in some cases in the difference between the flexibility of your market bid versus a reference bid. The market being what is used unless you're subject to mitigation, which again at least in our market is a pretty targeted and narrow situation.

But first of all with respect to the market bids, I think California is on the other end of the spectrum. The generators can submit from the minimum from the bid floor to the bid cap. They can change their bid by hour, and they can change it between the day-ahead and the real-time. I think in real-time it's--they can change it two hours, you know, right before the market is ready to run for the next hour.

I think, as Jeff noted, that has raised, you know, that's played a role certainly in some gaming situations. So the ISO was actually at one point looking at reducing that flexibility. I think there's a trend in markets where, I believe it's the market bid in some cases that's fixed between the two markets.

So when you talk about flexibility, I think you have to make that distinction. Is it the market bid? Or the reference bid?

Now the reference bid, you know we do use updated gas prices between the day-ahead and the real-time. And again those reference bids only kick in under limited situations. And I think there's actually a lot of opportunities because units typically aren't mitigated all day. Again, if you're mitigated you're mitigated for an hour, not for the entire day.

So I think gas markets tend to work not on an hourly basis, but by balancing periods, or days. And so there's probably a lot of flexibility to use market bids to manage your gas portfolio. That's the thing I think a lot of gas is done on a portfolio.

But, so I think again our--we do provide substantial flexibility, and then try to get the prices incorporated. Now there's some issues with start-up and min load bids which would be ex parte and I won't get into those and don't believe they'll come up later as well.

MS. NICHOLSON: I think, David?

MR. PATTON: Yes. I would say we have sufficient flexibility in MISO to reflect the changing needs of generators. I think we're in a similar situation as California.

The generators can change their bids between day-ahead and real-time, and they can change it hourly. Honestly, I think the concern about gaming is there, but it's not I think a big concern.

I mean, the gaming concern arises when you have a bad market rule and someone's taking advantage of it. And most of the changes in offers that are--that we've seen, both in MISO and in other markets, to take advantage of flawed market rules require significant changes from hour to hour that are pretty easy for a Market Monitor to spot.

I mean, it's not typically--you're not looking at someone changing their offer from $30 to $35; most of these strategies involve, you know, people dropping it to zero and then raising it to, you know, multi-hundred.

So--and the reason why, notwithstanding the fact that there are some potential ways to exploit flaws in make-whole payments of allowing that flexibility, the reason I think it's important to have a flexibility, and the reason I think New England is moving towards that, and it sounds like PJM is moving towards that, is I think all of us have gotten up here and said effectively we're mitigating a vanishingly small fraction of one percent of the unit hours or unit intervals.

I mean, we've said there's mitigation going on maybe one percent of the hours, two percent of the hours, but it's only being applied to a very small number of units. So if you calculate it on a unit-hour basis, you're talking about very, very small numbers.

But when you restrict flexibility, that's affecting the other 99.9 percent of the units. And they have things that they are trying to account for that are competitive issues, things that I think the Commission is aware of related to how a gas unit's costs change over the gas day, and what happens when you exceed your nomination and you start to be exposed to penalties and other things, that if you don't have the ability to modify your offer in real-time, it's not good for anybody.

Because, you know, if we over-burn on a gas unit and the pipeline doesn't want them to consume greatly more than their nomination, and we don't want them to either if we have other resources that are lower cost, so allowing them the flexibility to make those changes, and then having a mitigation framework that's got a reasonable threshold so that those sorts of costs can be reflected, is very, very important.

I think where we've all sort of run into, you know, a challenge and, you know, maybe some more than others, is in cases like the polar vortex where costs are just all over the place, and it's changing. You know, in the middle of the day it's changing, and it's hard to even get data on what, you know, what the costs are.

I don't think--at least I'll speak for myself, from my perspective I didn't envision the sort of circumstances we saw on some of the days during the polar vortex where the $1000 offer cap came into play. And so for those things I think you really do need to think about processes for accounting for those sorts of extreme circumstances in the benchmarks.

But, you know, day in and day out I think we have plenty of flexibility to handle, you know, the other needs.

MS. MOONEY: In SPP we have a great deal of flexibility in how offers can be submitted currently. So as far as the market offers go, there are day-ahead and real-time offers hourly. Start-up and no-load offers are currently daily, but I believe at least start-up offers may be changing to hourly in the future.

Because there is so much flexibility and these can be changed in real-time, we have some provisions in the Tariff to protect mitigation from that where the market participants are not allowed to change their mitigated offers in real-time except under very specific circumstances.

And if they have--and actually none of those circumstances includes the change in fuel costs. So if they do have a big change in fuel costs in real-time, they do--then we have a provision in the Tariff that suggests that they call the Market Monitoring Unit and tell us that they anticipate exceeding the threshold to where they would be mitigated, even though this is a legitimate cost.

And so then we can say, okay, you know, well the way to--we're going to make--you know, we have the authority then to say, okay, you shouldn't be mitigated; you can go change the mitigated offer.

So that's the way we deal with it. And we do, dealing with make-whole payments, SPP in designing the market put in a lot of protections around some of the make-whole manipulation just in that, at least throughout an operating day, an offer is made hole as committed.

So if once they are committed and then they go raise their offer, at least through that operating day and in some cases beyond that, the original offer would be used. So that's not exactly getting to the mitigation, but we do have some protections there, although I think it could be better in some places.

MS. NICHOLSON: All right. Thank you. Do we have any comments on that last question?

MR. QUINN: Could I just follow up a little bit on kind of the discussion about flexibility in bidding versus gaming?

I think, David, you talked about the fundamental issue really being kind of flawed Uplift or make-whole payment rules. So I guess what I'd kind of like to get a sense of from other panelists is whether you think that the flaw is--the way to fix the gaming opportunity is to fix the way you do Uplift rules? Or the way you are fixing the gaming opportunity is by making smaller, incremental kind of discrete changes to the amount of flexibility you allow to bid changes? Kind of once you identify a particular kind of game, you say, oh that gaming in my tariff is no longer allowed?

Because it seems like at some point changing the Uplift rules, if the Uplift rules made sense to start out with, you know, changing them or limiting them to avoid gaming might then limit legitimate make-whole payments at some point.

So just could you talk a little bit more about kind of this balancing of bid flexibility, preventing gaming, and then kind of how you're tuning your Uplift rules to manage all of that?

MR. PATTON: Sure, I'll jump in. The--so I think if it really is a flaw, and that's the source of the gaming, it is just vastly superior to fix the rule. Because there's no--there's no amount of restraint and limitations and other things you can apply to participants where you're not going to have costs accumulating by having that bad incentive just sit there.

And, you know, you may prevent the big cost from being incurred, but you're going to have lots of small costs. So I think I've always viewed it as extremely important to identify the source of the bad incentive and eradicate it, as opposed to dealing with it through restraints on people.

Now if there's cases where you have a well-constructed make-whole payment, like a garden variety bid production cost guarantee, there I think, you know, you have market power. And I would rather deal with market power by having an explicit market power mitigation measure that has clear criteria that identifies, you know, when somebody is engaged in conduct that should be mitigated and we take away their payment, rather than having a broader provision that affects everybody and is less targeted. Because those sorts--that sort of market power tends to be very local and specific.

MS. MOONEY: So in SPP we do have that

flexibility with offers, and I don't think that to this point we've had concern that that flexibility has been abused at all.

We have a very simple make-whole payment structure, and really just the types of make-whole payments that David was talking about with simple production costs within the day-ahead market and within the real-time market.

And right now we like it that way, but we do have calls for--from, you know, market participants for more complicated make-whole payments, and some of the types of make-whole payments that we have seen have more gaming problems in other markets.

And so at this point in time, what we're--our preference for the Market Monitor Unit is to look for solutions to the issues that are happening in the market that are making people desire these new types of Uplift that could potentially be games. Because to some extent, those make-whole payments, those new types of Uplift, could just be bandaids to, you know, protect people from something that's happening in the market that's inefficient that could be done better.

And so that's where we are right now in SPP, though we haven't had some of the experiences that others have had. We're just trying to stay in a place where there aren't strong incentives for these types of games to be played.

MR. BOWRING: So since we're a little bit behind the curve in terms of developing flexibility, apparently, at PJM, I would say that so we have the opportunity to do it right. And I think it's critical to do the design well so that the Uplift issues are thought through carefully, systematically, and the design is intended to prevent Uplift gaming.

Now even the simplest of Uplift can be gamed, as we've learned. So even simple approaches--production bid guarantees and so on--can be gamed. And if you allow complete and full flexibilities that apparently New England is about to do, and New York may be doing, and others are doing, that creates a--it's a very complicated set of incentives, a very complicated set of ways in which to affect Uplift.

And I'm assuming that others have thought about that, and their rules reflect that. But it is critical to design the Uplift rules and market power mitigation rules to permit maximum flexibility while preventing either gaming or abuse of Uplift.

MR. HILDEBRANDT: Yeah, I think we totally agree it's best to get the rules right, and then do as much as you can beforehand to get rules right and eliminate, or avoid gaming opportunities, and then continually monitor the market and respond to those and adjust market rules.

And, you know, I think with the bidding flexibility it's played a role in some. I think it may be--you know, there may be something in between where, you know, there's some limitation on them. But I think on balance it's better to get the rules right.

And I will say, at least in our market the software is getting awfully--you know, so bid cost recovery, it sounds simple on its face. Oh, just design good rules. At least in our market our software is getting pretty complicated in terms of, you know, we have multi-interval optimization with multi-stage generating units.

We pretend markets are 24 hours by necessity, when in fact the operation extends--you know, they're not just 24-hour periods. Or in the real-time we look out 4 hours, but units, their minimum run times, minimum start times go beyond that.

So I think you're not really optimizing over, you know, the true period. If you could continually run an optimization that really looked at all the constraints over the time period, but we're running into those limits. And that's the kind of scenario I think where it can get really hard to develop good bid cost recovery rules.

And, you know, you try to be fair in designing them. I think your original point. And you can design them to be fair for the 99 percent of the people that are entities where it's not going to be abused, but--and it's unfortunately if you have to design rules to prevent a hypothetical one percent of participants who might take advantage of that. Because I think there's a cost to that in terms of efficiency and equity to participants.

So, you know, we try to strike a balance and just continually scrutinize and develop new rules as the markets become more complicated.

MS. NICHOLSON: Unles there's any more comments on that question, I'd like to shift focus to the energy offer cap.

As a staff we'd like to gain a better understanding of the theory behind the systemwide offer cap, which is generally $1000 per megawatt hour. And how that relates to the market power mitigation provisions that you currently oversee.

So if you could currently explain--if you could, explain to us do the two play a complementary role, in your view? I think the first to answer would be Shaun.

MR. JOHNSON: Sure. There is, in New York, just as I'm sure all the other ISOs, this past winter certainly rekindled the discussion on a $1000 offer cap in the energy markets, and whether that was appropriate.

You know, we spend quite a lot of time in New York looking at this and really how--it's role in the marketplace. So maybe getting to your answer, I guess New York really sees this as sort of complementary to the market mitigation measures.

The market mitigation measures in New York are designed to deter the exercise of market power. And just as we discussed in sort of the previous question, most of those are wrapped around the concept of very complex market rule designs and the application of those.

The $1000 bid cap at its creation and inception ultimately provided a backstop assurance to consumers that, if all other things fail, there's still some protection that's available to consumers for something. We don't know what that is, but there's this backstop.

There's value in having a safeguard. I think the question that arose this winter is: Is the $1000 the correct safeguard? Or is it another number? Where does that belong?

In New York, ultimately we were comfortable with the $1000 cap. Even during this winter's historic pricing in New York, we did not have a unit operate at above the cap. So in our mind, that solidifies some of the discussion on our pricing period, that even in what we see as sort of the all-time peak, and given the increased gas that's coming into the constrained areas in New York, the increased capability that went into the past winter and additional capability coming in over the next few winters, returns to those levels are unlikely.

Even during those periods, this really did not become a true constraint, or did not inhibit a resource from being able to recover its costs.

So from that perspective, it is somewhat of an academic discussion in New York as to whether or not the $1000 is appropriate. And I think we're certainly still willing to engage in those discussions and see how that plays out, but ultimately we do feel that there is a need for a safeguard backstop mechanism in the markets. So we're certainly willing to continue the dialogue on whether the $1000 is the appropriate value.

You know, the one--the one consideration we've thrown out there is that, you know, we don't want to be sort of the sole institution left at $1000. All things being equal, that would create a unique seam that would not seem to be manageable in the long run.

But based on this past winter's conditions, we're certainly comfortable with that being a complementary role to our mitigation measures.

MR. McDONALD: Yeah, similarly I have always viewed the offer cap as a damage-control device in the event that you have circumstances that arise, uncompetitive circumstances that arise that your mitigation mechanisms weren't prepared to deal with, or in cases where they failed.

Having an offer cap does help limit the extent of the damage that consumers, or the market would incur until that can be remedied.

As to where the $1000 came from, I always thought it came from FERC.

(Laughter.)

MR. McDONALD: I think it's an administrative cap, but I don't know where it came from. But we were--does anyone here have enough institutional history to--I know, and I don't speak for California, but I did used to work there. I know we were encouraged to move towards the $1000 cap over a period of time, and that seemed to be the point that everyone was encouraged to gravitate towards.

I also agree with Shaun that, while I don't see from a New England perspective, you know, reflecting on last winter, I don't see a need for a change in that value. I do recognize the importance for RTOs that neighbor one another to have a common offer cap so that we don't get, you know, a disparity between the economics of offering into one RTO versus another. And that could play a very critical role in times when we do have these tight supply conditions.

MS. NICHOLSON: Sorry to interrupt, but I believe we have a tent raised and maybe we can hear something about the genesis of the offer cap from Adam Keech of PJM.

MR. KEECH: Hi. The offer cap issue coming out of the winter of 2014 is hugely important to PJM. We had resources that were limited by the $1000 offer cap. And as a result, couldn't offer in their true cost into the market. And as a result of those market rules, we couldn't set prices--had we dispatched those resources, we couldn't set prices that were commensurate with the controlling actions we were taking.

So from a fundamental market perspective, it was a limiting factor for PJM.

The second piece, and Richard brought it up in the first panel and I was too dense to realize what he was saying at the time, but the offer cap issue is also a coordination issue across the seams.

If we all go back and collectively say we're all going to determine different offer caps, we're going to perpetuate and potentially exacerbate a lot of the seams issues we talked about with interchange volatility during peak pricing conditions.

So from PJM's perspective, we think it's an issue that has to be addressed and one that should be addressed uniformly across everybody in order to not create further issues like we've talked about earlier today.

Thank you.

MS. NICHOLSON: And, I'm sorry, I misspoke. I assumed that you would talk about the genesis. My understanding from a PJM presentation was that the $1000 offer cap was from 1999, and it was associated with your market-based rate authority.

MR. KEECH: Richard can actually probably answer that better than I can.

MR. DILLON: Oh, that's pretty bad, isn't it?

(Laughter.)

MR. DILLON: The keeper of all knowledge here. Okay--

MR. BOWRING: It was actually the highest number anybody could think of at the time and then multiplied by five.

(Laughter.)

MR. BOWRING: Seriously. It was a number that people thought could never be reached, and as my colleagues here said, it was therefore a backstop. But it was just considered to be beyond the possible pale. That's where it came from.

MS. NICHOLSON: Thank you. I think, unless you'd like to make a comment, you can go on?

MR. DILLON: Oh, well I agreed with that. On the comment from Adam, even though we didn't hit the $1000 offer cap, the comment about the coordination goes, in SPP's case goes even beyond the seam. Because we have our scarcity pricing, and our penalty factor, VRL is what SPP calls it, is set based upon where the safety net offer cap is.

So that by its nature increasing means that we could increase the overall cost, and I go back to a comment made earlier of we have some events that that offer cap in PJM's case was too low. But if we change it for all periods, then I have a contrary issue of the prices may rise too high in the nonconstrained--"constrained" being cost wise--nonconstrained periods of the year.

MS. NICHOLSON: Thank you. Eric?

MR. HILDEBRANDT: Actually that was going to be one of my two main points. First of all, it's a damage control cap, 99.99 percent of the time that's what it is. And its biggest impact by far is in terms of setting penalty prices for different constraints, or the bids. But--which again, 99.99 percent of the time only come into play I would say really when, I don't want to call it a software malfunction, but it's a temporary condition that causes, you know, a constraint to become binding or violated oftentimes within the computer and not physically.

But that can have a huge impact on a day-to-day basis in a way that I don't think would have value in terms of being any more representative of scarcity. It would be a pretty arbitrary value in terms of, you know, trying to be a de facto scarcity pricing of some kind.

So that would be the day-to-day impact which I think would be detrimental to the market. And then these occasional situations--you know, I know maybe California is a little different. I think we have less volatile gas markets, less constrained.

You know, I don't want to say, you know, never would we get into a situation where the real costs would be that high, but I would think there would be a solution. If they did it would be a very targeted, temporary suspension or raising of it under very narrow conditions.

I guess I would argue you probably wouldn't really have a market, you know, so to pretend your, or redesign your market around hypothetical conditions when I would question the extent to which a market actually existed would be questionable to me.

MR. PATTON: Okay, so I've had a hard time getting too excited about the offer cap in MISO. I think when we've talked about offer caps previously we've talked about unit-specific offer caps, and those serve a very useful purpose, necessary purpose. They vary by unit, and they're way lower than the $1000.

The across-the-board offer cap was really not good at doing much of anything because it's too high to be a constraint on legitimate market power concerns. And you can't really lower it to try to be more effective because you start running into the problem that PJM just described that is the problem with any across-the-board cap, is the minute you start hitting levels at which units have costs that exceed that cap, then you have real problems setting efficient prices and motivating those units to be available.

So I think the greatest purpose of the offer cap is really to address, you know, gaming type of strategies where people can perhaps, if you have flaws in your make-whole payments again engage in strategies to get make-whole payments that are unjustified.

And I would be just as concerned about saying, well, the floor on people's offers is negative $2000, rather than negative $500 in MISO.

Well, and MISO has a lost profit make-whole payment, and the prices are $30 and the unit's not operating at max, we could end up paying somebody $2000 because it looks like they're losing a lot of money not running at their max.

Well that sort of condition comes about when you allow wide latitude in what people offer. And so that's the negative side. On the positive side, you have the $1000 and it does serve some purpose to limit those sorts of strategies if you have flaws that people can take advantage of.

But effectively, when--and this wasn't the case when the $1000 offer cap was put in place--but when shortage pricing started to emerge in an efficient form--which I wasn't here this morning, but I hope you talked a lot about operating reserve demand curves setting prices--and in the case of transmission shortages violations, transmission constraint demand curves which you all have seen and approved, so those are transmission shortages, those demand curves effectively serve as caps.

Because when suppliers offer above those levels, their offers just aren't taken. The model will say that the offer is too expensive and therefore not take it. So the role of the $1000 offer cap is greatly diminished under that regime. And I think the one remaining concern is the one that PJM raised, is are there scenarios where this would interfere with a competitive offer? And the answer is, yes, we've seen it. It was last winter when prices are $80 a million Btu for gas.

There's an awful lot of units that are going to have trouble representing their full costs with a $1000 offer cap.

Now I don't necessarily agree that it creates seam issues to have different offer caps. I don't know what--because we don't, you know, my units can offer at 1500 and a neighbor can offer at 1000, and it's hard to conceive of what impact that has because transactions aren't scheduled from generators offering in the neighboring market.

But that aside, I think there's nothing wrong with a sensible reform that would account for fuel price volatility and would look similar in different markets.

MS. MOONEY: I think the true luxury of going last is when there's nothing left to say.

(Laughter.)

MR. BOWRING: And I actually think there's lots left to say, as usual.

(Laughter.)

MR. BOWRING: So, sorry, Catherine.

So if costs imply energy offers greater than $1000, you have to allow them. That's the point. I mean, I talk about short-run marginal costs before and what doesn't belong, but one thing that very much does belong is the cost of gas. That's part of the short-run marginal costs.

And if the cost of gas implies your offer is $1500, that's what it should be. It should set LMP. It should not be an Uplift; it should set LMP.

Now just to go a few steps beyond that, when we looked back in response to some of the Commission's requests to us to look at waivers and so on, when we looked back post hoc, excluding 10 percent and simply looking at the actual incurred cost of gas, there were very few offers greater than $1000.

But if you look at the way prices are formed day-ahead, which is when people actually have to offer, and based on indices which is all people have and given all the frailties of the indices, we did see offers that should have been and would have been cost-justified to be greater than $1000. And that's really the test.

So my view is the cost-based offer cap has to be as high as necessary to allow the recovery of actual costs. But I would also point out that this really only occurs and can be expected to occur under extreme circumstances.

$1000 is still a very high number even in this day and age, except on the odd day when you have $100 gas. So it still does function as a backstop. So it's only under extreme circumstances that we would expect that to occur.

And what I would suggest is that the price-based offer cap, when cost-based offer caps are greater than the $1000, always be less than or equal to the cost-based offer cap, precisely because we're in extreme circumstances and to account for the kinds of things that Eric was saying, for example, and Richard was saying.

It's a way to prevent the exercise of aggregate market power under extreme circumstances when you can expect that individual owners actually have aggregate market power are pivotal.

I would also say there's no reason when costs are above, and imply a price above $1000, you need a 10 percent adder, particularly given that gas costs in those situations are going to be driven by indices, and given the huge bid/ask spreads are going to be at the high end of what is rational already and the 10 percent is not necessary.

And one last point about high offers is that under the current PJM Manual M-15, it has, if you read it carefully, some fairly bizarre provisions about maintenance multipliers. In fact, you can get to $1000 when you have $20 gas if you apply some of the maintenance multipliers. And those are entirely inappropriate and should not be the basis for cost-based offers greater than $1000.

So in summary, if your gas costs imply an offer greater than $1000, it should be a greater than $1000 that should affect the market. But there are some wrinkles there: price-based offers should be less than cost-based offers. And we need to be sure that it really is including your short-run marginal costs and only that.

Thanks.

MS. NICHOLSON: Thank you. I have another questions about the offer cap. We have another question about the offer cap. If anyone would care to discuss the theoretical basis for the level at which it seemingly is now, which is $1000. And also care to speculate about the, provided you have one, and also we'd like if you could talk with us about any potential implications from changing the offer cap either up or down.

Would anyone like to comment?

MR. BOWRING: I'll have to go first. So I think, just to pick up on what I said about price-based offers remaining less and equal to cost-based, I'm not sure who said it, I think it might have been Richard or someone else, you do create the ability in non-stressed times for units to make market-based offers greater than $1000. And say you set the offer cap to be $2000 or $3000. You then create the ability to do that day in and day out.

And if you look at the PJM aggregate offer curve, every day there are 3- or 4000 megawatts at $1000. So we could anticipate seeing 3- or 4000 megawatts at $2000 or $3000 if you simply raise the offer cap to $2000 or $3000.

I don't think that's appropriate. I think it does make sense to allow cost-based offers to exceed $1000 and to set LMP when the underlying gas costs indicate that, but not otherwise.

And as we indicated, I don't think there's a theoretical basis for $1000.

MR. HILDEBRANDT: And just to sum up, again I think I made it clear I would object, or see no rationale on a day-to-day basis to raise it from the current level. Under--Perhaps under some extreme circumstances, have a provision for that when the real cost justified bids above that.

But as far as the impacts, I think the real impact of that, the much greater impact, is going to be on prices. Again, it goes back to the, largely the different penalty prices on the various constraints, transmission constraints that are relaxed, or the highest priced bids that are always submitted at the cap. And those, I think you would--would result in price spikes without any real underlying--you know that don't really reflect underlying supply and demand conditions, or serve a, you know, a benefit in terms of some kind of scarcity pricing.

MS. NICHOLSON: David?

MR. PATTON: I wouldn't predict that there'd be any meaningful impact in MISO of raising it. Of lowering it, I think you would run into problems if you lowered it significantly.

You would just lose expensive capacity that can't offer their full cost. So I definitely would not suggest lowering it. But given the market that we have, it's hard to conceive that there'd be any impact of raising it significantly, with the exception of opening up the possibility of make-whole payments that you wouldn't want to see, to the extent that there's a flaw in any of the formula.

MS. NICHOLSON: All right. Thank you for your--

MR. MEAD: Could I interject a question?

MS. NICHOLSON: Yes.

MR. MEAD: Do any of you impose this offer-wide, or system-wide offer cap as a bid cap offered by customers, either in the day-ahead or the real-time market?

MR. BOWRING: Interestingly, in PJM the offer cap for DR is--was $1800, now $2100. That may not be the right answer, but that is part of the PJM design that DR is allowed to offer and set price at much higher than $1000 right now.

MR. HILDEBRANDT: I guess if what you mean is demand or load, at least in our--not DR, but, you know, in our--

MR. BOWRING: Not DR, but, you know--

MR. HILDEBRANDT: All right, in our day-ahead market I guess you could self-schedule demand, it goes in at a price above $1000. It goes in, it's represented as a price above $1000. So, functionally, yeah, even though there's not an explicit bid on it, it's treated as having a bid above $1000.

MR. MEAD: Just for context, as we know from this morning most of you have scarcity pricing in your markets, and there's a possibility that loads may actually have to pay multiple thousands of dollars for electricity. Do any of them have the opportunity raise their hand and say: That's too high; I don't want to consume at that level?

MR. BOWRING: Load in PJM can put in either fixed price offers or variable price offers. So I don't think there's any reason. Adam, tell me if I'm wrong here, but I don't think there's any reason why--I mean, you can certainly put in a bid of $1000. I think you can probably put in a bid of greater than $1000. I don't think there's anything to prevent that, but again Adam may correct me.

MR. KEECH: Yeah, so today--so we just made some changes to our DR offer caps. It used to be around $2100, which is what Joe said. Now it's around $1550 for this year is the maximum offer we will allow for DR.

But they could submit an offer at any time and electric curtail and the price gets beyond a certain--

MR. BOWRING: Well what about just load bids day-ahead? So prices--

MR. KEECH: Sensitive demand?

MR. BOWRING: Yes. You can put in any price you want, right?

MR. KEECH: Yep.

MR. BOWRING: Okay, that's what I thought.

MR. PATTON: And I think that's true in MISO, as well, in the day-ahead. And, you know, the fixed load is bidding infinity, right? So there's no cap.

And in real-time, if you're not talking about DR then there's--you know, then there's nothing to talk about in terms of price instability All the load is just a price taker.

MR. MEAD: Okay, so if there's some load that doesn't want to buy at greater than $2000, it can say so?

MR. PATTON: Yeah, it can but it would be in the form of--some form of DR, a participant in one of the DR programs.

MR. BOWRING: Not in PJM. You can put in a price-sensitive bid for load in the day-ahead market at whatever level you want. So you could put it in at $2000 if you wanted.

MR. MEAD: What about the other ISOs?

MR. JOHNSON: So similar to PJM, we have price-cap load flexibility in New York. So either a fixed or price-sensitive load points that can be in. And I'll look to Rob to correct me, but I believe the validation functionality for price-cap load works the same as it is for generators. I don't think they could put in an offer of willing to purchase something above $1000. I think that would be the highest point that they could assume their willingness to purchase.

MR. McDONALD: I have to say, I'm not entirely sure.

(Laughter.)

MR. HILDEBRANDT: I believe we do have a cap of $1000 for price-sensitive load, but fixed load is, while not infinity, it's ultimately put in the model at a higher price than $1000. And I'd have to check what the price of that would be.

MS. MOONEY: Off the top of my head, I'll have to check. I don't know for sure. I suspect we're the same as MISO.

MS. NICHOLSON: Thank you. i H have one more question before I turn it over to my colleagues.

As a wrap-up, if you could all discuss the rule that, in your estimation that market power mitigation plays in price formation in your markets. I'd like your thoughts on that, the role that market power mitigation plays in price formation.

I think we start with Jeff.

MR. McDONALD: So there's I guess a couple of ways to answer that. I would say because we don't mitigate energy bid curves very frequently, it plays a very small role in price formation as an empirical matter. But I think it plays a very important role because it helps provide validity and assurance to those participating in the market that the prices that they're getting are competitive and that they can count on that.

So even though we don't see high frequency of mitigation or a high frequency of resources being mitigated on their energy curves, just having the mitigation there and having the rules explicit for how we're defining uncompetitive circumstances, and how we're going to apply mitigation, is a very positive assurance for those participating in the market.

MR. HILDEBRANDT: Yeah, and I guess I would put it is, while a direct impact of mitigation is relatively infrequent and small, except, you know, when they're--in you know, in isolated cases where there really is local market power and it's being exercised, which have been few and far between, but it's the indirect effect.

I think in my opening comments I mentioned I really see it as a component in our market. You have strong market power mitigation. And when you combine that with, in our market it's a resource adequacy program that ensures enough capacity is there, and then equally or more important you have the forward procurement, the actual energy procurement. Different tolling contracts. Financial contracts for power by the large load-serving entities, which of course, you know, the market power mitigation facilitates that because ultimately that kind of establishes the opportunity cost of the suppliers in terms of when they're looking at a forward contract, what they should forward-contract at.

So I think you really need all those pieces, or at least they're certainly complementary. And again, all that forward contracting and tolling agreements is one of the reasons the market power mitigation is actually invoked so rarely in our market, or so infrequently.

MR. PATTON: Okay, just because I think there may be an impression that there's been some disagreement on this panel, let me clarify.

I think sometimes you hear disagreements on the market power mitigation regimes around the edges, but I think you heard the same thing from virtually everyone, is that all of these regimes, while they're slightly different and, you know, some have a dynamic test in this area, and some not, and they're all very effective. They're all relatively focused. They all impose mitigation very infrequently.

And I think if I were to go look at the State of The Market Reports from all these markets going back the last 8 or 9 years, it would be hard to find evidence of significant unmitigated market power, with one exception. And that is, Uplift payments, which we've all dealt with in different ways and tried to make sure we have a handle on.

So the concern about over-mitigation, or I'm sorry inadequate mitigation, I think there's virtually no evidence of that. And I think largely because these are sound regimes.

So then you have the flip side, which is the over-mitigation. I find every time I'm on a panel talking about mitigation, I have to figure out whether I'm talking about over-mitigation or under-mitigation.

So let me talk about over-mitigation. It would be extraordinarily difficult to make a credible argument that any of these mitigation regimes have any adverse effect whatsoever on price formation adequate incentives.

And in part that's the case because if you design good shortage pricing you don't need generators to raise their offers to set an efficient price.

What I always stress is, would you agree with this principle: If the market were perfectly competitive, should it be designed to allow generators to recover fixed costs and efficiently send signals to build new units?

And the answer has to be, yes. In a perfectly competitive market, nobody has an incentive to raise their offers. So if you're going to tell me that somehow we need generators to raise their offers to get adequate price signals, then I would say that has to be evidence of bad market design.

If you don't have good shortage pricing, I would call that bad market design. And we've gone down that path. Texas has gone down that path. I hate to drag them into this discussion, but they're struggling to try to be an energy-only market. They've gone down the path of why don't we let a certain class of suppliers do whatever they want? They may well get good price signals. They've concluded we're not getting good price signals, and sometimes when we don't want price spikes we do get them, and that's equally problematic.

We tried that in New England with the push bids. That didn't work very well. And that was designed to try to get us out of having RMR contracts with generators to generate better price signals. Ultimately, New England implemented operating reserve demand curves, and that's worked great.

So I think if you have a good market design, you don't need people to raise their offers. If you don't need people to raise their offers, there's no conceivable way that market power mitigation could interfere with price formation, particularly since the mitigation is so vanishingly infrequent.

So I have some strong views on that topic.

(Laughter.)

MR. PATTON: But I think that hits both sides.

MS. MOONEY: Yeah. So--in SPP our market is very new. Obviously we don't have a lot of empirical results to show on the effectiveness of the mitigation. But I joined SPP right about the time we received results from a study that Potomac Economics did showing that nearly half of our resources were in frequently constrained areas.

And so about that time, you know, market power mitigation has kind of been my focus, and working with others in the MMU to be proponents of the need for the automatic mitigation in SPP. And we're updating that study now.

We do feel, with that many resources and that much congestion, that the automatic mitigation is very important in SPP.

We do see a lot of transmission being built in SPP right now to address some of those specific transmission congestion concerns, and so we're hoping that as we move forward we will have, you know, more expectations of, you know, a really competitive environment. But we do have some of the concerns, and feel that the mitigation is very important, especially at this time.

MR. BOWRING: This time I agree with almost everything David said--I think probably all of it. So--

(Laughter.)

MR. BOWRING: No, seriously, I thought he said it very well. So in the PJM market there is relatively low frequency in the energy market. But there's still a significant set of units that are mitigated, 50 to 100 units mitigated on a regular basis.

Therefore, there is a significant impact on prices in constrained areas of market power mitigation. And it's an appropriate impact.

I mean, as David said, the downside of over-mitigation is requiring people to behave competitively. It's pretty hard to see much of a downside there.

The downside of under-mitigating is allowing people to exercise market power. So I think the risk--first of all, I don't think there is over-mitigation. But the risk of over-mitigation, as David said correctly, is very small, particularly when you have a good market design. And I agree with that test of a good market design.

In PJM, however, there is virtually 100 percent mitigation in the capacity market. There is, as we like to say, endemic market power in the capacity market, and there always will be unless the Department of Justice changes its mind about something, which I don't expect.

So there's highly concentrated ownership, and there always will be market power there, and there will be market power mitigation. But I don't believe the market power mitigation in the PJM capacity market has had a price suppressive effect.

I think the rules of the PJM market have had a price suppressive effect, but it has not been the result of market power mitigation. So I think it's critical in the capacity market, but I think it's having its intended effect.

And finally, in the regulation market, although a smaller market, many of the hours of the regulation market are also mitigated because of structural market power. And again I think in large part because the bulk of the price is actually opportunity cost, which is a result of interaction between energy and regulation.

The impact of mitigation in the regulation market has been salutary as well. Thanks.

MR. JOHNSON: So I think, similarly to what everyone else has said, mitigation in New York from a direct market impact really only plays a role in our constrained areas. That's really the primary way that mitigation would actually directly impact prices within the market. And that is a very small portion of our percentage of time that mitigation is actually applied and impacts prices.

I think, you know, there is likely an indirect impact somewhat of the potential for mitigation, but similar to what was just stated, maybe the downside of the indirect impact is it makes resources cautious and incents them to operate in a competitive manner.

Now that isn't forcing them to do anything. It is I think a risk that is evaluated from each individual. You know, that may be a poor analogy, but it's somewhat analogous to the speed limit where folks generally drive around what the posted speed limit is. There are always exceptions, and obviously maybe the competition analogy here is a little off, but in a lot of markets the--or at least in this case, I think that may be one of the indirect roles that market power mitigation measures play in price formation, is that concept that folks are incented for concern over perhaps some day being subject to mitigation to operate in a competitive manner.

MS. NICHOLSON: All right, is there any question on that--

COMMISSIONER CLARK: I did have one, and hopefully it's really quick. So I didn't hear any great groundswell to either raise or lower the $1000 offer cap. But I wasn't intrigued by the idea of a, sort of a safety valve that Joe talked about coming out of the experience of PJM this last winter.

And I'm just wondering, have folks given thought to administratively how that would be done? Would it be fairly easy to implement? Would it be difficult to implement? And are there any pitfalls that the Commission should be thinking about if we try to incorporate something like that into the tariffs?

MR. BOWRING: So I mean we've thought about it, and I think it would be straightforward to implement and actually not very much different than implementing the current offer cap. So I think it would be straightforward to do it the way we described it.

MR. PATTON: I think in MISO and many of the other markets the thing that you're really worried about are gas units. So, you know, and MISO asked me for my ideas and I said the most sensible one to me, it sounds like, is to fuel-price adjust the offer cap based on some very high assumed heat rate.

And so find the highest, you know, gas price that's prevailing and adjust upward based on the movement in the gas price. So that's really the only case that we've seen, or that I can conceive of where the BAL totally could be great enough that you'd run into trouble with a $1000 offer cap.

MR. HILDEBRANDT: I don't want to say what would be easy--I don't want to speak for our software people, but I think if you were prepared adjusting the caps and the various penalty factors I think might be straightforward. And I think the harder part might be, you know, having--establishing up front what the criteria would be. How would you raise it? I'm assuming a lot of discretion would not be provided to the ISO, or that would be an issue, are you leaving that. Because typically this would have to be a pretty quick decision by an ISO.

And I know in the West, you know, we have good--I think we have fairly--we're confident in our day-ahead. Most of the gas is traded day-ahead for the day, and you do have indices, fairly deep liquid indices for that.

I don't think we have, you know, a clear or objective way of determining what a--you know, if things were to change after that, what a--we don't have indices for real-time, basically, interday gas. At least in the West we don't have that, or certainly not ones that we think would be straightforward to pick.

So I think that would be one obstacle.

MS. NICHOLSON: Thank you, very much. I'd like to offer our Commissioners Clark and Bay, if you'd like to make any closing remarks to this panel?

COMMISSIONER CLARK: No.

COMMISSIONER BAY: No.

MS. NICHOLSON: All right. Hearing none, I think we'll end the panel. I would like to thank wholeheartedly our panelists. Thank you very much. We had a very interesting discussion.

And we're going to now take a 10-minute break and reconvene for panel four I would say at maybe 3:50. Thank you, very much.

(Whereupon, a recess was taken.)

MS. NICHOLSON: Hi. Could we start to take our seats, please. Thank you.

(Pause.)

Hello. Thank you very much for those of you who have come back to our second Price Formation Workshop for our fourth and final panel today.

Today we have a group of market participants and we're here to discuss the impacts of market power mitigation provisions and the energy offer cap.

And I'd like to note we have some RTO representatives here on the side, and they may jump in if they find they'd like to make a statement just to help make sure we have a factual record. So we all understand--

(Off-microphone comment.)

(Laughter.)

MS. NICHOLSON: I'll start with introducing our panelists. We have Joe Cavicchi from Compass Lexecon. He's speaking on behalf of EPSA.

We have Abe Silverman from NRG. Edward Tatum from ODEC. Jeffrey Nelson from Southern California Edison. Charlie Bayless from North Carolina Electric Membership Co=Operative. And Patrick Connors from WPPI, and I believe you're also a member of TAPSGs

MR. CONNORS: Right.

MS. NICHOLSON: So thank you very much, panelists. We really appreciate you taking the time to speak with us today about energy offer cap--energy offer mitigation and offer caps.

My first question is about the cap. And I'd like if you could tell us a little bit about what circumstances might lead a resource to have energy supply costs that exceed--incremental energy supply costs that exceed $1000 per megawatt hour, and how often that might occur.

So we can start from left to right, and I think you're pointing to Abe Silverman. Okay, you want me to go--all right, Patrick.

(Laughter.)

MR. CONNORS: I'm on the wrong end. Thank you. I appreciate the opportunity to be here today.

We're primarily in the MISO area and, you know, we have not exceeded the $1000. I mean, our incremental prices are not--that exceed the $1000, you know, very infrequent.

So I mean, we don't see, you know, a need for the cap to be above $1000 a megawatt hour because we just don't see those prices in the Midwest.

We haven't seen the gas spikes in the Midwest. We've got gas coming in from, you know, the West, the East, and the South, and North, and so, you know, we're probably not going to see those types of price spikes in the Midwest in particular.

MR. BAYLESS: I think the only thing we've seen in PJM that's actually caused the price to exceed $1000 is natural gas prices exceeding $100. They got up to $140 last January, and that produced some generator costs over $1000.

There's some question as to the causes of gas prices to go that high, but that's something else. And this is not a regular occurrence. This has happened once. It happened last January, and as we heard a little while ago in PJM when the Market Monitor looked at sort of after the fact all of the offers that were put in, that they determined $9,118 I think should be given to market participants who exceeded the cap.

So I don't think it's something that happens really at all, and, you know, it's just not that big of a factor.

MR. NELSON: First, thank you very much for having Southern California Edison here today.

So a little perspective on the $1000 prices of generators. In my role in Edison, we've got about 14 million customers we serve, and we've largely divested our generation. We have a peak of about 23,000 megawatts, and we have about 3500 megawatts that we still control.

However, we do significant contracting with generation where we typically toll it. So we're participating, we're bidding, we're very familiar with the bidding rules and the cost structure.

As far as direct costs over $1000, I had some guys pull all the gas prices we've seen in the last five years. We didn't see anything get close to $1000 from sort of a marginal cost basis based on gas.

We tried to look at sort of the worst units that were in our system. They're around 17,000 heat rates. We got up to about $350 if we looked at gas prices.

Now with that said, we have some interesting gas penalties that can be applied. And at times, the gas penalties, depending on how you're managing your gas, could result in production costs over $1000 if you're evaluating penalties.

And this gets into some of the larger issues of electric/gas coordination, particularly in light of when an ISO is instructing someone to do something with coordination of the gas system, the appropriateness of penalties under some of those circumstances.

So I would say the actual costs we have not seen happen for energy, but the potential with penalties is out there.

MS. NICHOLSON: Just a follow-up, could you give some examples of the type of penalties?

MR. NELSON: Yeah. There's two major gas distributors in California--SoCal Gas and Pacific Gas & Electric. At times they'll have OFOs, overflow restrictions. And some of the penalties can range as high as $100/MMBtu, plus the replacement costs of gas.

So under those circumstances, you can start seeing gas up into the $115ish, $120 at some of the extreme things we saw per MMBtu.

MR. TATUM: Thank you, so much. I'm Ed Tatum with Old Dominion, and I just would like to say that we are an electric co-operative. And so we're not-for-profit. We're owned by our members.

Old Dominion is a member of NRECA, and we have cousins and close friends and family over at APPA as well. But the things that we like to talk about a little bit, just to understand who we are, we have 11 members. It's about 1.2 million people that we serve in the Delaware, Maryland, and Virginia area.

We have about 2000 megawatts of generation that we own that supplies a little less than 50 percent of our energy needs. So we appreciate the ability to go to market and get that.

We have about 2500 megawatts of load from 2013. So we're owned by our members. We're not for profit. It's very important to us, one, that the lights stay on; and two, that the price to pay for those lights staying on is affordable.

And I believe your question was with regards to what's driving the $1000? Is that where you wanted to go with that?

MS. NICHOLSON: Yeah. Just generally--

MR. TATUM: Generally--

MS. NICHOLSON: --what could cause the resources, incremental energy costs to exceed $1000.

MR. TATUM: In PJM, and Dr. Bowring talked a little bit about it, we can have those prices exceed $1000 due to demand response as well. But I think one thing that Joe said today that I particularly appreciated, not that I didn't appreciate everything--

(Laughter.)

MR. TATUM: --was that fuel-driven costs, I think are what we're talking about, I appreciated your statistics. I wish ours were so good. Our smart guys looked back over the past three years for the top 10 days at the relevant PJM hubs and came up with 11 days north of $90, 5 days north of

$100, highest price $140 as Charlie said, and translating to heat rates, you know, that can come up to anywhere from 1400 to 1800, maybe 1900 LMP.

Now those prices, we're talking 5 days, 11 days over 3 years? So that's a very small percentage of the time. And so we saw that as a driver, but we get a little concerned about it because during the morning we talked about scarcity pricing. And we also talked about the capacity market. But there was, what I heard was a conclusion around the table that those are all actually administrative constructs, right?

You know, we've got a capacity resource adequacy construct, and now we're talking about scarcity. And I'm thinking scarcity is going to come into play when prices are high, and I'm thinking, Joe, you'd agree with me on this, when resources are scarce.

And so if that's indeed the case, as we look here in this little forum at the energy market, which from my perspective is as close as we have to actually approaching markets, we need to make sure that we address both of those aspects as well that's going to be in a relationship to it.

The simple answer, though, we had some price excursions. I can't say why they went that high. Ours were not driven by penalty gas. We looked very carefully at that. It was a pure price play on our system. But I'm uncertain if we'll see that again.

MR. SILVERMAN: Abe Silverman. I can tell you, we have bought gas that cost us more than $1000 to run generators. We burned up to $1500 gas in New York. You know, we were out there in the interday market buying Transco Zone Six at I think it was $82 per MMBtu, burning it in something like a 20 heat rate unit.

And there's no ability to reflect that price. You can't call up the New York ISO, or you can't go into the New York ISO portal and show the actual cost of your gas. You actually physically cannot put in a number bigger than 999.

And, you know, we were on the phone with the Market Monitor saying: What's going on here? We're being forced to operate at a loss.

And you ask what drives that? Well I mean obviously the fuel costs are the big issue. We have the same thing in PJM.

Now we as a company elected not to come in and seek recovery for that, for a whole host of reasons, but we had gas that we were buying at somewhere in the hundred dollar plus MMBtu range, burning that in our generators and our price caps would have been significantly over the $1000.

And, you know, you ask what else can cause that kind of thing? The penalty gas is a huge issue. You know, I mean we operate in the California market. The California gas market is truly a national market. Really, it's an international market.

We're starting to see a lot of gas flow out into Mexico. And when prices in the East and in the Rockies go up, the gas is just sucked out of Southern California and sent to those higher priced markets.

So we continually find ourselves in the CALISO being subject to out-of-merit dispatch, required to do large interday gas buys, with no ability to reflect the actual cost of that gas in our bids.

I'm sorry Eric had to leave, because one of the things that we've talked about a lot is, you know, he trumpets the ability of CALISO system to accept interday reoffers.

Well that's true for your energy curve, but the vast majority of dispatches of units like ours--in fact, 78 percent of our dispatches in the past 12 months--were out-of-merit dispatches for which we are being mitigated. And it's down to, you know, this very complicated start up no-load cost, which I know is subject to a docket currently, but, you know, we're coming into another winter and these issues still are not resolved.

And it's somewhat amazing to me that, you know, really eight months after the polar vortex things like we're still arguing about, should the price cap--when you can come in and 100 percent verify that you spent more than $1000 for that gas, that's still not allowed to set price?

I just don't understand that. And, frankly, if you'd told me that eight months ago, I would have said: Well, there's no way we're still going to be arguing about this coming into the winter of '14-'15.

So, you know, and I think these things are only going to get worse as we sort of see this environmental and societal trend away from coal-based dispatch really to gas. And, you know, I heard a lot of folks say in the earlier panels, well, this isn't a problem for us. You know, at MISO we don't have this problem. In California we don't have this problem.

You may not today, but when you turn over 50 percent of your fleet in the next decade, or you have these kind of issues that Southern California is going to have with gas just simply flowing out of the system, these problems are coming for you.

And I think people would have said exactly the same thing about PJM 12 months ago. And so, you know, I think the market just needs to be allowed to work. And frankly, my hope is that everybody will be able to agree on some of these really common-sense reforms like allowing the actual price of your gas to be reflected in the market.

MR. CAVICCHI: Thanks again. We'd echo certainly to some degree the comments here. I think the most important thing, I think it was good to hear from folks who actually go out and buy the gas, since I don't go buy gas, that the prices really were high enough to have the running costs be greater than the offer cap.

And in the type of market design we're relying on here, it's absolutely critical that when those costs are being incurred at the margin to meet demand, that they participate in setting the price.

It would seem just nonsensical not to have that be the situation. I think one of the comments Abe said that's really been on my mind is, and I said it earlier today, the system is changing. The gas system now is going to be asked to perform differently going forward.

If you look at some of the ideas PJM has on its capacity performance product, there are going to be generating units out talking to gas suppliers about much different types of arrangements than they've ever asked for previously. And it's almost certain that it will drive up the cost both at the margin and over longer term.

So it's really--you know, it is really time to take that into account, and I think recognize that, even if you have a higher offer cap, or a higher I would say systemwide cap, I mean what we're really hearing here is that the practical impact of that is almost nothing.

So the more important impact is for the system suppliers to be able to accurately represent the costs they're incurring.

MS. NICHOLSON: Thank you. I think we have more comment requests from Ed, and then Jeffrey.

MR. TATUM: Thank you. I don't know if you've got more questions for the panel, but I think Abe and Joe just both made a very good point. And I think their point was that if we're seeing prices, whatever prices that we're seeing, we do need to be able to reflect it in the LMP. Okay?

But here's Old Dominion: Load, generation, not-for-profit. We understand both sides of this business. We would prefer that if we're going to reflect things in LMP that they be accurate.

There is a big question as to whether--and at least in our mind, as to the level of accuracy that LMP forms during high-price, high-constrained events. We are concerned about that from two aspects.

One is, and I think the previous panel did a great job talking about it, all the different inputs from back and forth as to the inputs to the model that forms LMP. We've got indices. We have estimates. We have various things.

I can give you over a year an idea of how much we spend in our household for food, but if I have to recreate that number based upon a certain type of meal that I prepare, and if maybe I have mac and cheese more often than not, so if we're putting together costs and we're coming up with these averages and back-and-forth, in general we're going to be pretty good during normal, unconstrained, let's-have-leftover night operation.

But when it gets time for Thanksgiving, when you've got 12 people coming over, and you've only got 10 plates, and everything is going, that cost might not be reflective. So that's one part.

The other part that we're very concerned about is the accuracy of the models that are used to set price and to form price in LMP. In PJM we have thermal models. These do not recognize voltage constraints or other types of limitations.

We also are concerned from some of the extreme weather event operations that we've seen whether or not the model captures fully all constraints.

So, but for the fact that we have concerns with the model, but for the fact that the inputs might not be accurate during extreme events, we do agree that it should be in LMP. But unless we're able to get straight on what that is, we would prefer, and we strongly feel the need for an offer cap to remain in place and that it be sane and empirically derived.

Thanks.

MR. NELSON: And just real quickly, I want to echo some of the comments that Eric Hildebrandt made specifically for California. I don't support raising the $1000 cap. As I say, empirically it's not binding.

There's a few issues where penalties may be assigned that should be treated as that, a few issues that are off to the side not core to the market design, but what does concern me, a comment that I think was made by Joe, that there's no impact, or very infrequent.

I disagree with that. The ISO, our California ISO has had a material amount of price spikes in its real-time market. They're very short. They're transient. They're often extreme. And generally the only people that are able to capture this are virtual bidders because it's too late for the physical people to move. It's not physically signalling. It's just a financial.

And those often happen because there's been a minor change in the model from day-ahead, and that results in two problems as a load-serving entity that picks up a lot of uplift. If they change the model, the constraints are more often going to bind at a more extreme level. And if the model or assumptions of loop flow happened, it creates Uplift and load gets saddled with that Uplift.

So seeing the price cap raised raises a whole slew of other parameters and pricing within the model. And to the extent financial transactions are probably the main ones dealing with this, there's a high risk of increased Uplift to load. So I'm concerned with that dimension.

MR. SILVERMAN: So I'll just make this real quick. I think this is an important point about that Uplift in load. We're also a not-small retail electric provider, a competitive supplier in a number of the Eastern States, and honestly we have a real problem with Uplift as a retail provider.

We can't hedge that. But if these price spikes, I mean these costs, are put into LMP, we can hedge. So from a competitive retail supplier point of view, we are much better off as an industry allowing these prices to be hedged than we are simply adding, you know, having these completely unhedgeable large costs that are applied to retail transactions after the fact.

I mean, you know, I think a lot of us saw some real extremis in a lot of the smaller electric players, you know, retail, competitive retail suppliers on the East Coast and largely it's because of these extreme price spikes. But not because of the price spikes themselves, unless they were just really badly hedged, but in large part because of the Uplift that was associated with it.

So to the extent we can move those things over into LMP, I think the entire industry is actually much better. And, frankly, consumers are better.

Another point I'll just make to my friend, Ed, here is that I don't think any price we've ever bought gas for has been more scrutinized than it was in some of these incredibly high-priced days.

So rather than the scrutiny going down on Thanksgiving, actually I think every last carrot and every last pea is being audited to the enth degree. So I'll just submit that.

MR. TATUM: I think you're right on that.

MR. BAYLESS: I think that 99 percent of the time, as Ed said earlier, we've had 11 days in the past three years where prices hit $90 or $100. So 99 percent of the time generators are compensated properly under the $1000 price caps.

It's only on the rare occasion that the price, legitimate prices exceed $1000. And in those situations, I would say the market is not really behaving properly when fuel costs go that high. And I don't think that the price should set LMP on those occasions, because generators are getting too much--getting rewarded for a market that is not behaving properly.

With that said, I think the generators that actually incur costs above $1000 should absolutely be reimbursed every penny that they actually incur. I would probably throw in the 10 percent adder in PJM for that.

(Laughter.)

MR. BAYLESS: I mean they have to produce, and I think they should be reimbursed. But I don't think that it should set LMP because it unjustly rewards the other 99 percent of the generators on a day that the market is not behaving rationally.

MS. WIERZBICKI: Charlie, just to follow up on that, if the generators should be reimbursed for the costs they've incurred, but those costs shouldn't be reflected in LMP, where does the money come from? Is that just from Uplift?

MR. BAYLESS: Uplift. I mean, if you start adding in the 10 percent adders and things like that, the numbers will probably change. But in PJM last year, that number came to $9,100. And I don't think that you're missing out on huge price signals for $9,100 if you put it in Uplift.

MS. NICHOLSON: Patrick?

MR. CONNORS: Thank you. At WPPI, even though we have own-generation and we have long-term purchases to meet all of our supply, and although we're 100 percent hedged, you know, we still--you know, we think LMP should reflect the short-run marginal costs as discussed in the last panel.

I mean, we don't necessarily agree with the 10 percent adder, but, you know, we support making sure entities get their true costs. But it needs to be their true, actual costs. And someone else probably needs to help make sure and verify that that is the true cost and so they're not inflating the LMP in their costs in their offers.

MR. CAVICCHI: I would just offer to Charlie's comment, I don't think anybody has perceived that the gas markets were working improperly. And they're probably some of the most, you know, seasoned markets we have. They've been restructured for a long time.

There's been no evidence that I'm aware of that any of the pricing--I know folks here and the staff did some investigation. You know, the fact is there are willing buyers and sellers in those markets, and the price is what it is, and the bid-ask spreads might be high because information flow is a little bit stymied over a short period of time, but if we're going to accept those as market prices we should also accept any prices that flow from those as being relevant.

And I think this last point is important.

Setting those prices up there, not only does it alleviate the Uplift but it creates the incentive for folks to hedge going forward. And one of the last things you want is anyone getting comfortable that they can rely on the markets instead of hedging. Because in the long run, it's the hedges that get the new supply in that protect the consumers, and they'll factor in those costs, and consumers will end up protected. And I would argue that the costs will actually be lower than putting them into Uplift.

MR. TATUM: I'll just raise my hand from here on [name tent falls to floor]. Sorry about that. It's late in the day.

I just wanted to start off in answer to your question, but before I do I think Joe makes a good point as to why it's so important for this entity that owns a lot of generation to still have an offer cap.

The prices we saw in January of this year were after the PJM waiver was granted and there was no offer cap. So I just point that out as something I think is very important. There's a number of other reasons. Hopefully we'll have a question as to why it's important, and I'll give you the others later.

Mary, you were asking about the after-the-fact and how to take care of that. And we had that experiment in PJM with the first waiver. And as Charlie was pointing out, there was about $583,000 that was applied for compensation. And of that amount, $9,118 was granted.

So that's a lot of scrutiny. It's after-the-fact scrutiny. I mean, Joe looked at it very carefully, and his team. And that's something that can take time. But you don't have that time if you're trying to set LMP.

You might, at best--in PJM they have the ability to recalculate LMP if they've made an error in the model run. I think there's like 48 hours, something to that effect.

So at best, if we're trying to get some of these prices in LMP that--because we're not confident about how they were formed, or the model is still not working, and then take a look to make sure they really work for actual cost, that's going to be very hard to do.

And after-the-fact accounting can get you closer to what some believe are actual costs; others might disagree. But just to add some more flavor to that, there's probably room for a little bit of an offer cap change as well as continued mitigation after the fact.

MS. NICHOLSON: Thank you. I think we have David Patton who would like to comment.

MR. PATTON: Yes. I didn't think I'd be hearing a debate on whether these things should be included in prices or not. So I felt like I had to say something.

I think the mechanism is to review costs and ensure that folks are submitting accurate offers are in place at prices below $1000, and those same processes could be utilized to ensure that people are not inflating their representations of gas costs above $1000.

I know we did see prices as high as $80 a million Btu in the MISO footprint. So I wouldn't rule out that this is an issue in MISO. But one important dimension of this is, if we're increasingly relying on gas and we're concerned about things like fuel assurance, I'll bet you half the RTOs in here would tell you that they would love for more of their generators to put in dual-fuel capability so they could switch over to oil.

All of those things are motivated by fully reflecting the cost of gas in their offers. Because if we expect the price--if we can expect that the price is going to rise as high as the gas price drives the electricity price, then the folks who put in dual-fuel capability and can default over to oil are going to make a huge amount of money.

Anything that we do to keep that signal out of the LMP and transfer it to Uplift is--just mutes that price signal and leads us down the road of people talking about mandates and much less efficient means of getting that sort of fuel assurance.

So it's very important to get this priced.

MS. NICHOLSON: Thank you very much. I have another question we'd like to hear more about: The role that the offer cap plays to ensure just and reasonable rates. For example, if the mitigation rules are working such that competitive pressure disciplines offers, do we have enough competitive pressure that there's disciplining offers not subject to the cap to assume just and reasonable rates will be the outcome?

So again, I'd like some thoughts on the role that the offer cap plays in just and reasonable rates.

We can go down the line, or if you all have something to day. How about Charlie?

MR. BAYLESS: You know, from just looking at the staff report last week on offer mitigation, what I saw was that basically 80 percent of the time, maybe close to 90 percent of the time, there was little to no markups.

It was only when you hit the 90th percentile or so that there was substantial markups. And, you know that's when the supply curve starts to become very inelastic and there's a greater price needed to bring on an additional megawatt of generation.

And you start to hit limits there. And I think that it was capped at about a 300 percent markup. But I think the offer cap is needed for those situations when you're looking at extreme markups to ensure that rates are just and reasonable.

When you hit the very edge of the supply curve, there is I think a few competitive forces left. I mean, when you're at the 50th percentile, there's a lot of generation out there bidding, competing to seal that megawatt; but as you get farther and farther to the right, there's fewer and fewer megawatts left to sort of put competitive pressures on each other.

So I think you need a price cap just for that last 10 percent to keep a check on things.

MR. NELSON: And I think a reasonable damage control cap is essential to ensure just and reasonable rates. And I became an absolute believer of that in 1998 when our original ISO design had a service called "replacement reserves." And they had a hard constraint: Thou shalt buy a certain amount of reserves.

And it happens that they wound up short with reserves. And we wound up clearing this replacement reserve at $9999. That was the price, just shy of $10,000, because the bidder believed that was the cap.

And it turned out ultimately when we dug into it the cap was 17 digits.

(Laughter.)

MR. NELSON: So that was a lesson to me that you can't operate a market without some sort of damage control in there.

It also helps mitigate a perverse incentive. I was talking about a lot of the spikes we see are not scarcity events; they're solution technique issues. They're limitations in a very rigid mathematical model trying to represent a flexible reality. Parameters that bind even for a transitory amount can send very high spikes.

The financial players can capture that. And the higher those go, the more incentives you provide people to find ways to make the spikes happen. So I believe having a reasonable level prevents a 17-digit bid from clearing, and it also keeps everyone's incentives within a range of reasonableness.

There is no, if I hit it for five minutes I'm set for life incentive behind people.

MR. TATUM: Tatum with Old Dominion. So as others have said, the stop-loss mechanism, we agree with that. In PJM, we think it is essential because a three pivotal supplier test is a structural test. And so it doesn't make judgments on competitiveness of offers.

And so this provides discipline for the resources, the owners who have to actually put the cost in to get the costs right. So that's important.

As was mentioned earlier, we think it's important to curb overly exuberant fuel suppliers. And only after the cap was lifted last year did the prices go to that level.

Finally, my smart guys in power supply advised me that the cap really for hedging purposes does provide guidance to folks fashioning various hedging products. And so it prevents a, if you will, a sky-is-the-limit forward pricing.

And so as we sit with this real vestige of a market that is closest to a market than anything else we have, taking those things into account is very important.

When we talked about, on the other panel, the origin of the $1000, I was teasing and I said my Dad put that out there, but what it--what I've heard was that it's basically three times the worst unit on the worst fuel. And, you know, even today, that's old. We've got better units, and we've got shale coming in. And so $1000 is not too shabby.

MR. SILVERMAN: So, you know, first of all we will settle for five-digit offer caps. That's just fine, as long as the decimal point is at the end. I'll sign on the dotted line right here.

(Laughter.)

MR. SILVERMAN: But, you know, just real quick, I think it's really important as a fundamental question. We need to distinguish between cost-based and market-based bids into the market.

You know, and to my mind the cost-based bid cap is without basis. I mean, you know, frankly I understand the politics. I understand, you know, we're all very sensitive to the price that load ultimately sees. But there's no justification for it.

If I can have an invoice saying that I paid $1200 for gas, then the cost on the system for the marginal unit on that day was $1200. And, you know, this is me talking, but the only just and reasonable rate is to set the LMP at $1200 for that day.

You know, I mean I personally think market-based bids should go there, too, but I can see the debate on that. And I think we can have that healthy debate. But we should at least be able to agree that the cost-based bid should be allowed to set price.

You know, the third thing, I know people talked a little bit about the marginal supply stack in both New England and California in the report, which I thought the New England portion of the report was really well done, very analytic, and I thought it was actually kind of fascinating. And when I read that, I thought, okay, this is market fundamentals at work.

Because in New England during the high load times, gas--particularly during the winter--is an incredibly scarce commodity. I think no one would disagree to say that New England is seriously gas constrained.

And so when we put our bids into that market, we have to inflate the risk premium that we're putting in. Of course within the rules, and within our best guess as to what that gas is going to cost us. But that's a totally reasonable market response given the fact that I'm going to be going out into that market and trying to buy gas when frankly there isn't any.

And I can see I just piqued someone's interest over there. I probably used the wrong terminology. But that's okay. You know, I think that concept is right. And so the fact that there is more spread in those very high-priced days doesn't surprise me in the least because you are accounting for the kind of risks you're going to see and the volatility you're going to see in the actual market.

But again at the end of the day, when I have that invoice and I can show it to the IMM and demonstrate that I bought that gas, the rules shouldn't be any different if it's $872 than if it's $1,072. And, you know, I think we need to move in that direction awfully quick or else we're going to be in the same situation this winter--in fact, we probably already are--that we were in last winter where we were losing up to $5 million a day buying gas, running it through the machine, and selling at a lower price.

And that happened to us in California. And, you know, it's incredibly frustrating from the generator's point of view because these market rules are telling you, hey, if you don't perform when you're dispatched by the ISO you're going to be referred to FERC Enforcement for investigation.

You know, we have a, whatever-the-cost kind of mentality at NRG where will go out and buy the gas if we're dispatched by the ISO if it is actually physically available for purchase.

And so, you know, it's this very strange situation that we find ourselves in. And, you know, I tell you, it keeps me up at night, why my management is going to come to me going into the winter of '14-'15 saying hey, we saw these problems last winter. Why aren't they fixed?

And, you know, I don't really have a good answer for them. And all these after-the-fact waivers like we did in PJM, it helps but we--we--in both California and PJM, and the response was entirely different.

PJM tried, really tried actively to fix the problem. At least from our perspective the CALISO didn't. And so we're kind of in this weird spot where, depending on where we are in the country, we may or may not be running our units at a loss. And they're big numbers.

MR. CAVICCHI: I think it's very clearly the case, especially listening to Abe, that current offer caps can be unjust and unreasonable. So that signals that something needs to change--not that I'm an expert on what just and reasonable means from a legal perspective, but economically they're not just and reasonable.

You know, we need some form I think of offer caps, because as everyone said they are what we see as an important means of damage control, or stopgap, or whatever you want to call it, in the event that we have an unusual event.

Arguably, though, they're not really doing much because any time generators really use them outside of actually basing their costs on them, they're pricing themselves out of the market. If you really think about it and look at it, it's not really a good way to make money.

But setting that aside, they are definitely something we need. I think one comment I'm hearing about the oddities of the solutions of the models, I mean that to me seems to be a problem that ought to be resolved so that we can have offer caps that are fair and not have oddities in software be driving results.

If we're going to have a shortage in the software to come up against shortage pricing in an appropriate way, you know, as opposed to some disconnect between the day-ahead solution and then real-time where there's loop flows. And I don't know where that stands in California now, but, you know, that shouldn't stop you from picking offer caps that are fair.

MS. NICHOLSON: Patrick?

MR. CONNORS: I mean markets are not always competitive. As we have seen in other panels, there's going to be times when, you know, because of the inelastic demand there's a generation--there's a series of generation outages or transmission outages, you know, and there's going to be times when entities could exercise market power.

And I think it's important that you provide some protections so that people have confidence in the market; that the market price being set is reasonable. And so I think that is a critically important part of this.

You know, we've seen, you know, that this can be a very expensive issue. In past--you know, the California crisis of 2000, I mean there was times when it was very difficult and expensive to go backwards and try to fix these problems after the fact.

So let's make sure we don't get into that situation.

MR. TATUM: Thank you. It's Ed Tatum with Old Dominion. Abe and I agree on a lot of factors when you get to the high level piece of it, and I want to say that I agree that actual costs--if you get a fuel bill, you know, you should be able to get that compensated.

The problem is, until we get a lot of other things put into place, you're not going to have that fuel bill in your hand in time to set the LMP. Okay? We have gas-electric mismatch. We're running indices back and forth. We don't know, at least in PJM, at the time the things close. So that's kind of a problem.

With that being said, we do have the model issue. And I just want to step back for a minute and try to manage our expectations.

April 1st next year will be the 18th birthday, we believe, however you count it whether in dog years or whatever, of LMPs. We've been doing this 18 years. We've got it. We're almost out of adolescence, but we're still learning about how we work and how we feel, and back and forth.

There's a lot of things that still need to be shaken out. We've got LMP and price formation and offer caps during normal, nonconstrained times when the models are pretty good and the prices are relatively less volatile such that our estimates are pretty good.

And then we've got this other conversation about high-priced times, max gen emergencies, and back and forth. And trying to think about those things in that context I think would be helpful.

MS. NICHOLSON: And I see a couple of more tent cards, and I'm going to have to apologize that we're going to have to move on, given the timing here.

I'd like to ask, we'd like to ask if you can speak to, as resources, do the reference level or marginal cost estimates that underlie market power mitigation in the markets you participate in, do they adequately reflect the cost of resources?

And also, if you feel that they do not, are you given an adequate channel that you can contact the Market Monitor and discuss with them if the estimates are incorrect?

And finally, are there features for setting reference levels that could be improved in the markets? And if so, what improvements would you suggest?

MR. QUINN: And maybe just to help us focus the discussion, we've done a good job of kind of covering what happens during kind of crazy, super crazy price fuel events, maybe for the purposes of the next discussion we could focus on kind of mildly crazy, you know, volatile fuel price instances. Or just kind of closer to normal but still instances when you think maybe your costs are changing in a way that maybe a current reference level calculation makes it challenging to have that kind of consultation.

MR. SILVERMAN: I can start off with that, if you want. And, you know, this is my chance to say something a little bit nice, which is that I think for the most part under normal circumstances most of the markets work in most time frames.

But there's a couple of caveats. The time frame really matters, whether you're talking about day-ahead or real-time. I think we're very happy for the most part with the day-ahead formation process. You know, I'm sure my traders will probably kick me when I get back for saying that, but I think it actually does work pretty well.

Under normal circumstances, I think the real-time works reasonably well, particularly in those markets where we can go in and update our intraday prices. New England is moving to that. New York has had that for awhile.

And, you know, in this last cold weather event both New York and New England I think, and I think PJM as well, were actually very useful, you know, where you could pick up the phone and talk to the Market Monitor, when we were seeing prices that were sort of outside the normal thresholds of what you'd expect to see.

And, you know, again I'm sorry Dr. Hildebrandt is not here because the experience in California was exactly the opposite, where there was absolutely no flexibility and no real interest in talking to us about what was happening when we were getting run over in the gas market.

And, you know, part of that is a function of the tariff and the way they don't allow bidding of minimum load and startup costs. And when you can't actually take your cost to the market and show them, plus you combine that with some of the gas penalties that were referenced earlier, you really run into some major problems.

So but, you know, I think in Eastern markets for the most part I think it works pretty well. And, you know, it may also, when we had running out of fuel oil, which was happening, you know, liquid oil of various sorts during the vortex, it took a couple of days but each of the Eastern ISOs really worked with us to include sort of last-minute opportunity cost adders into those bids to reflect the fact that, you know, it was going to be three or four days before we could restock a particular facility, or even 24 hours in some cases.

So that was very useful. And it's nice to be able to say something--you know, to receive that kind of cooperation.

MR. NELSON: Well first I want to be very careful about ex parte because I know there's issues before the Commission regarding startup and min load in the CALISO, so I'm going to avoid that topic altogether.

Generally the discussions going forward is that in the vast majority of the markets, particularly in California, they have explicit capacity requirements. So what we're really trying to do--it's actually the law that we maintain basically a 15 percent reserve margin on top of peak in the right locations.

So we have a whole capacity construct that is outside of our ISO market that serves very important retirement and new-build. So in our markets, we're really looking, and I very much agree with the Commission staff report on short-run marginal operating costs.

And to that focus, I believe the ISO works pretty darn good. There's an issue that's developing that I think needs to be on everyone's radar screen. We're moving further and further away from traditional heat rates times gas prices and moving much more into environmentally constrained opportunity cost world.

The ISO, our CALISO does a pretty good job with that. We have a lot of hydro. Almost every single unit we have has environmental constraints. So the traditional run-all-you-want doesn't really exist in California.

And coupling that are, I'll call them, additional environmental markets that are being moved into the energy market. In particular, California has a GHG market that prices production of GHG. Our ISO does a good job capturing that in the way its baseline works.

However, with EPA 1.11(d) we don't know what's going to happen outside of the California footprint. I'll note that California, through their EIM, is expanding into six states eminently. We're not sure how they're going to handle the environmental restrictions there.

Other states are on the drawingboard. To the extent you monetize the environmental costs, it fits pretty good within a traditional framework. To the extent you come up with some sort of new, creative way of managing emissions rates, everyone is going to have to be cognizant of that.

We're going to have to check to make sure that the current structures are still compatible. And I don't know what's going to come down the road, but it's a concern on my radar that I think we should all be looking for.

So right now I'm feeling pretty good about it. Thanks.

MS. NICHOLSON: Does anyone else have any comments? Yes?

MR. CONNORS: Yes, thank you. I think one area that we think is clearly an issue that needs to get addressed is the transient price spikes.

You know, that occurs quite regularly and it's an issue that if we had better coordination, or even joint and common markets--I know that's--I think we could eliminate a lot of those transient spikes. And that does add up significantly over time.

Another area is going to be the comments that came up, you know, more environmental dispatching is clearly on the horizon. And we're going to need more transparency in calculation of the opportunity cost and how that gets calculated and put into the price.

And so that's an area that I can see coming down the road that we're going to need more information on and we're going to need better pricing in that area to make sure we get the prices right.

MS. NICHOLSON: Ed?

MR. TATUM: During less crazy times, we've got two states. One is where we've got a transmission system with little or no constraints. In that situation, I think in PJM I believe we're in pretty good shape with regards to price formation.

The Manual (indicating) like this, it references 11 other manuals. There's a lot of documentation, which shows you how difficult it is to do it. But it's detailed. It's intricate. And so no constraints, good development.

When we get to constraints, though--and again we're talking about reactive and the inability to model some voltage problems--that's when we're going to have less-than-optimal price formation in those less crazy times.

And we've seen that. When gas first went under coal, we had the promise of markets that was finally coming true. The less-expensive gas units were offering day-ahead, but we couldn't use them because, lo and behold, we still needed those higher priced coal units to provide that reactive.

But not to worry because we had to pay these guys opportunity costs as well as the more expensive. We got that one fixed. But you get my point. The modeling during less crazy times, if we're constrained and if we're not capturing the constraints.

MR. SILVERMAN: Just two real quick points. One, a defense of transitive price spikes. You know, they actually do help form forward prices. I don't want people to leave the room thinking that they serve no purpose.

You know, we get very quickly thinking about sort of what we've learned in the ERCOT energy-only market, but that's, you know, by design. Those are important in setting the forward prices and promoting hedging.

You know, I totally echo what the other folks are saying about the environmental attributes in dispatch. But, you know, the other piece of it that we have to remember is we have a lot of units--and Ed kind of was getting at this--that are committed for various reliability reasons out of merit, put on at minimum load.

And those megawatts, they're just pumping out unpriced megawatts into the market. And I think, you know, particularly conservative operations, I mean we're in these very constrained cold or super-hot days, and we're seeing prices go down because so many units are on at minimum load. It's a big issue in California. It's a big issue other places.

Extended LMP when it's implemented, you know, the full extent what MISO's doing right now is sort of baby steps towards this will help price those unpriced megawatts, but that's the other piece of the sort of day-to-day operations that I think has a big impact on price formation.

MS. NICHOLSON: Thank you. I think we have time for one more question, if that's okay with everybody, related to offer flexibility. In particular, do the markets that you participate in allow sufficient flexibility in the offer rules for you to reflect changes between the day-ahead and real-time market and changes across the operating day?

And to the extent they do, how does that affect your bidding behavior?

MR. SILVERMAN: I will happily take that one. This is my favorite topic of all. So first of all, kudos to ISO-New England. They are planning on implementing hourly re-offers I think on December 1st.

It's been a long time in coming, and that will hugely help that market. New York has had this frankly since the beginning of their market, as far as I know. And it's kind of always baffled me why other ISOs don't just take the sort of proven, very effective New York ISO strategy and run with it.

I think Joe talked about that we do not have that in PJM at the moment. I think it's actually pretty important, particularly for, you know, for CTs. And again, you know, if we're getting dispatched in the day-ahead market that's fine. We go out and buy our gas. We have some reasonably approximation of what it's going to cost, leaving aside all the electric-gas coordination issues, which are a problem. But for the most part, we get there.

It's those dispatches after the day-ahead commitment runs when we really have a problem, either in the residual unit commitment process--you know, they tell you at six o'clock the evening before the operating day that you're going to be on--or in real-time.

I mean, you know, again 78 percent of all of our dispatches--we have a 5000 megawatt fleet that we control in California--78 percent of our dispatches from March 2012 to March--2013 to 2014, were out of merit.

I mean, you know, how are you supposed to procure gas in that kind of environment? It's really, really hard, and you just simply--you can't get the price formation right if so many--if such a large percentage of your fleet is being dispatched out of merit. And it just exacerbates the gas issues for everybody else.

MS. NICHOLSON: We have Patrick, and then Ed.

MR. CONNORS: I would just take exception to that. I don't think anyone is disagreeing that if prices do change real-time that people shouldn't get their fuel costs reflected, you know, in their offer.

So I think we should allow changes to the extent costs truly changed. But to the extent costs haven't changed and people are just trying to increase prices to see if that happens to change the market prices, I don't think is necessary and I think it's counterproductive.

MR. TATUM: Thanks. So in PJM we currently don't have sufficient flexibility. We're hoping that by this winter we will. And I think you heard about that at the previous panel.

Gas-electric mismatch is a primary driver, but even after the day-ahead clears if you're not taken we do see the need to be able to change prices just because we don't know the price of gas, and we don't know if we're going to be running back and forth.

And so the ability to change in real-time is important. We're evaluating it right now. Submitting up to 72 schedules for updating interday costs is on the table. We're going to be developing fuel policies for those interday offers, as well as looking at units committed in advance of the day-ahead posting.

And Old Dominion is of the opinion that all those things will help. But still, we need a little bit of resolution to that gas-electric mismatch and hopefully one day alignment of those actual days. Thanks.

MS. NICHOLSON: Joe?

MR. CAVICCHI: I would just add on that, I mean--and I think the importance of PJM in examining it has been totally heard--but Abe is talking about one problem with his units being committed out of merit in California, which is one kind of problem.

But you have--and Ed's getting to the problem in PJM. If you ask units to generate in real-time based on stale day-ahead prices, and you present that proposition to them the day before, you're going to find that they're not going to respond the way you want them to respond.

And you can put all the fixes in the world, even into the capacity market, and you're still going to have the problem. So I think, you know, you can't emphasize enough how important it is for the resources to be assured that they're going to be able to bid consistent with their costs. Because otherwise, even if they get dispatched day-ahead, they're going to be concerned about even inc'ing, you know, producing a little more in real-time, you know, if they haven't really incorporated that into their offers.

And if their offers in any way are being affected by indices from the day before, you know, they may not be able to actually capture all their costs. So it's something that really can't fall from the forefront, especially with winter coming again.

MS. NICHOLSON: Thank you. Can we hear from Jeff, and then Charlie?

MR. NELSON: Yes. I heard the question was do we have enough flexibility? In the ISO, like we talked about, we are allowed to have a different bid every single hour, and we're allowed to change the bid in real-time every single hour. So we have about as much flexibility as you can get.

There may be other issues going on, but the flexibility doesn't seem to be a problem, at least in my view.

In our ISO I'd say there's an issue where they attempt to update the gas prices as current as they have, but again as Dr. Hildebrandt talked about, we don't have a reliable interday index, which makes updating intraday right now just something that's not a dependable or reliable situation.

I personally hope that will evolve, because I believe intraday dispatch is going to become more and more important as we integrate more and more renewables where the actual production is not known until real-time.

But the current state of the market is a reliable index doesn't exist.

MR. BAYLESS: NCEMC has 12 gas units. They are all located in the Duke region of North Carolina. So they are physically located out PJM. But since we have load in PJM and outside PJM, a few of those are committed to serving our load in PJM.

Being outside of PJM, I don't know that any of those have ever been called on out of merit order. So it's not usually a big problem for us. But I think we do need to work on gas-electric coordination and try to make it so day-ahead, when you're bidding in, that, you know, you can see some real prices in gas instead of just indexes.

MR. SILVERMAN: Just one--don't underestimate the value of ICE data. Both day-ahead and intraday. I mean, there's a lot stuff that trades on the exchanges, and I think we're headed more and more there.

When I started, and I'm just going to make up some numbers, they're not right but, you know, like 30 percent of our stuff was traded on ICE, and now it's virtually 95 percent, and sometimes a lot of days more.

It's such an attractive platform for the traders, it really is used a lot. So I think that solve some of these intraday liquidity problems. I mean, it's not going to help you on the weekends at, you know, ten o'clock at night on a Sunday night when you're interrupting some kid, some guy's birthday party for his kid, to call him up and ask him if he has that extra few hundred decatherms you need.

But during, you know, sort of under the more routine operations, I think it's going to get you there. And, you know, in the California stuff--and I'm very sensitive to the minimum load and startup costs talking about the price in the current filing--but the things that aren't changing are things like the inability to bid those costs.

And so when you talk about flexibility in the CALISO, it's kind of like they have this theoretical flexibility that you can use, but in day-to-day operations the vast majority of your units could be committed. And, you know, this gets into the multiple-stage generation issue as well, but can be committed to something resembling minimum load where none of that flexibility matters.

It just doesn't matter. It's just words on the page and you can't use them. You can't access that portion of the tariff because of the way the CALISO dispatches its system.

So we are constantly stuck in this two to four, and sometimes five-day lagging gas price in California.

And, you know, I feel like I'm picking on poor California, but it's the place where these things seem absolutely the most stark and problematic.

MS. NICHOLSON: All right. Thank you very much, panelists. We've had a really interesting discussion and we appreciate your time. I think it's time to wrap up, unless any of my colleagues have any questions.

MS. WIERZBICKI: I don't have a question, but just as part of wrapping up, we do have one more Price Formation Workshop scheduled for December 9th where we will discuss operator actions.

Speaker nominations for that workshop are due tomorrow. So for our audience here in person and our audience watching the live webcast, do consider submitting speaker nominations for that.

(Whereupon, at 4:53 p.m., Tuesday, October 28, 2014, the workshop was adjourned.)